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IDAHO PUBLIC
UTILITIES COMMISSION

April 23, 2015

Jean J. Jewell, Secretary
Idaho Public Utilities Commission
472 West Washington Street
Boise, Idaho 83702

Re: Case Nos. IPC-E-15-01, AVU-E-15-01, PAC-E-15-03
Direct Testimony and Exhibits of Dr. Don C. Reading

Dear Ms. Jewell:

I have enclosed the Direct Testimony and Exhibits of Dr. Don C. Reading for filing in the above-referenced dockets on behalf of the J.R. Simplot Company and Clearwater Paper Corporation. Please contact me with any questions.

Very truly yours,

Gregory M. Adams

Enclosures: Direct Testimony and Exhibits of Don C. Reading
cc: Service list (e-mail only)

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S PETITION TO MODIFY TERMS AND CONDITION OF PURPA PURCHASE AGREEMENTS	))))	CASE NO. IPC-E-15-01
IN THE MATTER OF AVISTA CORPORATION'S PETITION TO MODIFY TERMS AND CONDITIONS OF PURPA PURCHASE AGREEMENTS	))))	CASE NO. AVU-E-15-01
IN THE MATTER OF ROCKY MOUNTAIN POWER COMPANY'S PETITION TO MODIFY TERMS AND CONDITIONS OF PURPA PURCHASE AGREEMENTS	))))	CASE NO. PAC-E-15-03

DIRECT TESTIMONY AND EXHIBITS OF

DR. DON READING

ON BEHALF OF

J.R. SIMPLOT COMPANY AND CLEARWATER PAPER CORPORATION

APRIL 23, 2015

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Don Reading and my business address is Ben Johnson Associates, 6070 Hill Road, Boise, Idaho. I am Vice President and Consulting Economist for Ben Johnson Associates.

Q. HAVE YOU PREPARED AN EXHIBIT OUTLINING YOUR QUALIFICATIONS AND BACKGROUND?

A. Yes. Exhibit No. 201 serves that purpose.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CONSOLIDATED DOCKET?

A. The J.R. Simplot Company (Simplot) and Clearwater Paper Corporation (Clearwater).

Q. WHAT IS THE PURPOSE AND GENERAL CONCLUSION OF YOUR TESTIMONY IN THIS CASE?

A. I have been retained by Simplot and Clearwater to review the petitions filed by the Idaho Power Company (Idaho Power), Avista Corporation (Avista), and Rocky Mountain Power (RMP) asking the Idaho Public Utilities Commission (Commission, IPUC) to modify the terms and conditions of Public Utility Regulatory Policies Act of 1978 (PURPA) contracts. I will explain why the recommendations of the three utilities is an unreasonably overbroad approach. Both the Federal Energy Regulatory Commission (FERC) and the Idaho Commission have correctly stated that PURPA projects need contracts of duration longer than five years to allow for financing of a PURPA generation facility. I will explain why the examples used by Idaho Power to criticize PURPA are misleading, and will demonstrate that Idaho Power's claim of a "flood" of incoming

PURPA contracts is misleading. It is far from certain from the evidence provided that these projects will ever be built. I recommend the Commission maintain the current 20-year contract length for qualifying facilities (QFs) eligible for the IRP methodology rates, or at a minimum for non-intermittent QFs, and if adjustments need to be made they should be through the calculation of avoided cost rates and not limiting the term of the contract.

Q. YOU INDICATED YOU ARE TESTIFYING ON BEHALF OF SIMPLOT. DOES SIMPLOT OPERATE OR INTEND TO DEVELOP QF PROJECTS IN IDAHO?

A. Yes. Simplot currently operates an existing QF project at its fertilizer plant in Pocatello, Idaho, which utilizes a renewable fuel in the form of waste heat in an industrial cogeneration process and has a nameplate capacity of 15.9 megawatts (MW). It has sold the output from that plant under a series of PURPA contracts, and recently entered into a one-year replacement contract for that PURPA facility. Simplot will need another replacement contract within the next year. Although Simplot has recently obtained QF contracts with published avoided cost rates, it has also requested indicative pricing under the IRP methodology and considered increasing its generation well above 10 average monthly MW on a consistent basis, which would require a contract containing the IRP methodology avoided cost rates. In recent years, I understand that Simplot has considered contract lengths of up to seven years for this project.

Additionally, Magic Reservoir Hydroelectric QF (Magic) is a wholly owned subsidiary of Simplot. Magic is a nine MW hydro facility in Southern Idaho, and currently has a 35-year contract to sell the output to Idaho Power, which expires in 2024.

Simplot also recently contacted Idaho Power to request indicative pricing for a cogeneration QF sized up to 25 MW, to be developed at the new Idaho Project potato processing facility in Caldwell, Idaho. I understand that Simplot faces difficulty even analyzing the viability of this proposed facility without a fixed rate schedule in excess of five years. It is likely the project will not proceed if the Commission reduces the maximum contract length to five years.

Q. YOU ALSO TESTIFIED THAT YOU ARE TESTIFYING ON BEHALF OF CLEARWATER. DOES CLEARWATER OPERATE OR INTEND TO DEVELOP QF PROJECTS IN IDAHO?

A. Clearwater owns four generators at its wood pulp, paperboard, and tissue manufacturing facility near Lewiston, Idaho, which primarily utilize as fuel the black liquor byproduct of the paper production process and wood waste. These four generators are cumulatively capable of generating approximately 109 MW of electrical output. Although they primarily use a renewable fuel in the form of biomass, these facilities also use the steam output as process steam in the production of pulp, paperboard and tissue products, and are each certified as cogeneration QFs. Clearwater has previously sold its output from these generators to Avista under PURPA contracts, and Clearwater has maintained its QF certification to allow it to again make sales under PURPA in the future. Currently, Clearwater operates under a 2013 agreement whereby Clearwater uses its generators to serve Clearwater's own load, and Avista compensates Clearwater for its excess generation at the retail electricity rate. The 2013 agreement remains in effect until June 30, 2018, but provides Clearwater with a limited right to terminate its energy sales to Avista with 90 days notice.

Additionally, I understand from communications with Clearwater personnel that Clearwater and Avista have had periodic conversations over the last five years about the viability of siting a large cogeneration project at Clearwater's Lewiston facility. Given the large and nearly constant steam demand at the Lewiston site, this facility could support a base-load plant of an incremental 75 to 125 MW that would approach 70% thermal efficiency depending on the sizes and types of prime movers selected for the project. The net impact of this project would be an incremental lowering of greenhouse gas emissions for the western U.S. as it would displace base-load coal plants and assist the State of Idaho to comply with the E.P.A.'s recently proposed, and likely promulgated, Section 111(d) carbon reduction rule. The expected economics of such a project would likely require non-recourse financing with terms of at least 15 years, with 20 years being a more feasible term. A limitation of a five-year power purchase agreement takes this type of high efficiency, greenhouse-gas-reducing project off the table as an option at Lewiston. Clearwater does not think this artificial limitation is in the best interest of the ratepayers of Idaho.

Q. ASIDE FROM PURPA OR SERVING THEIR OWN LOADS, ARE THERE ANY OTHER VIABLE OPPORTUNITIES TO SELL THE OUTPUT FROM PROJECTS LIKE SIMPLOT'S AND CLEARWATER'S IN THIS REGION OF THE COUNTRY?

A. Unlike the three regulated utilities that petitioned the Commission in this docket, state law bars Simplot and Clearwater from selling electricity at retail to any customer. This is also true of neighboring states that largely bar the sale of electricity at retail. Additionally, FERC has stated that Section 210(m) of PURPA is intended to relieve utilities of their PURPA obligation if there is a sufficiently competitive wholesale market for QFs to sell power. But there is no such economically viable wholesale market for the sale of electricity that meets PURPA's requirements in this region. Therefore, aside from PURPA sales to utilities, neither Clearwater nor Simplot have a legal or economically viable market, retail or wholesale, to sell electricity.

Q. IDAHO POWER SUGGESTS THAT THE IDAHO COMMISSION HAS THE AUTHORITY TO REDUCE CONTRACT LENGTHS FOR FIXED AVOIDED COSTS TO ANY LENGTH IT CHOOSES. WHAT IS THE ORIGIN OF A LONG-TERM CONTRACT WITH FIXED AVOIDED COST RATES?

A. PURPA is a federal law that directs FERC to implement regulations that encourage cogeneration and small power production from renewable resources. I have included as Exhibit No. 202 a copy of the FERC regulation regarding a QF's right to a legally enforceable obligation for a specified term, which is contained in 18 Code of Federal Regulations Part 292.304. The FERC regulation provides that each QF shall have the option:

> *(2) To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either:*
>
> *(i) The avoided costs calculated at the time of delivery; or*
>
> *(ii) The avoided costs calculated at the time the obligation is incurred.*[1]

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[1] Exhibit No. 202 (containing 18 C.F.R. § 292.304(d)(2)).

Q. **COULD YOU PLEASE STATE FERC'S EXPLANATION AS TO THE INTENT OF THIS RULE, AS PROVIDED IN THE FEDERAL REGISTER AT THE TIME FERC PROMULGATED THE RULE?**

A. Yes. I have provided as Exhibit No. 203 an excerpt of FERC's Order No. 69, which was published in the Federal Register on February 25, 1980, and explained FERC's decision to adopt this regulation. FERC stated:

> *Paragraphs (b)(5) and (d) are intended to reconcile the requirement that the rates for purchases equal the utilities' avoided cost with the need for qualifying facilities to be able to enter into contractual commitments based, by necessity, on estimates of future avoided costs. Some of the comments received regarding this section stated that, if the avoided cost of energy at the time it is supplied is less than the price provided in the contract or obligation, the purchasing utility would be required to pay a rate for purchases that would subsidize the qualifying facility at the expense of the utility's other ratepayers. The Commission recognizes this possibility, but is cognizant that in other cases, the required rate will turn out to be lower than the avoided cost at the time of purchase. The Commission does not believe that the reference in the statute to the incremental cost of alternative energy was intended to require a minute-by-minute evaluation of costs which would be checked against rates established in long term contracts between qualifying facilities and electric utilities.*
>
> *Many commenters have stressed the need for certainty with regard to return on investment in new technologies. The Commission agrees with these*

> *latter arguments, and believes that, in the long run, "overestimations" and "underestimations" of avoided costs will balance out.*
>
> * * * *
>
> *Paragraph (d)(2) permits a qualifying facility to enter into a contract or other legally enforceable obligation to provide energy or capacity over a specified term. Use of the term "legally enforceable obligation" is intended to prevent a utility from circumventing the requirement that provides capacity credit for an eligible qualifying facility merely by refusing to enter into a contract with the qualifying facility.*[2]

Q. I RECOGNIZE THAT YOU ARE NOT AN ATTORNEY AND CANNOT PROVIDE A LEGAL OPINION ON FERC'S INTERPRETATION OF ITS OWN REGULATION, BUT AS A MATTER OF ECONOMICS, IS IT YOUR OPINION THAT A FIVE-YEAR CONTRACT TERM WILL, IN FERC'S WORDS, "PREVENT A UTILITY FROM CIRCUMVENTING THE REQUIREMENT THAT PROVIDES CAPACITY CREDIT FOR AN ELIGIBLE QUALIFYING FACILITY"?

A. No. The QF will not be able to cause the utility to avoid future capacity additions if the contract term is shortened to five years. One of the ways a utility can avoid, or "circumvent" in FERC's terminology, entering into a QF contract is to limit the contract term to such a short period that being able to finance the project becomes impossible. The contract terms recommended by the three utilities in this case of two, three, and five years

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[2] Exhibit No. 203 at 2 (containing FERC Order No. 69, 45 Fed. Reg. 12214, 12,224 (Feb. 25, 1980)).

are all too short to allow a QF to be economically viable or to provide, and be compensated for, the capacity value.

Q. AS A MATTER OF ECONOMICS, IS IT YOUR OPINION THAT A FIVE-YEAR CONTRACT TERM WOULD SATISFY "THE NEED FOR CERTAINTY WITH REGARD TO RETURN ON INVESTMENT IN NEW TECHNOLOGIES"?

A. No. The only "certainty" that comes to mind with a QF contract term of five years or less is that it is very unlikely the project would ever be built. This conclusion is supported by the fact that utility non-PURPA power purchase agreements are for terms much longer than five years. For example, Idaho Power's Neal Hot Springs power purchase agreement is for a 25-year term, and Idaho Power retained the right to extend the term of that agreement. In his comments on the Neal Hot Springs contract, IPUC Technical Staff, Rick Sterling, identified the right to extend the term as one of the "benefits" of that agreement in recommending its approval.[3]

Q. ALL THREE OF THE UTILITIES ASK FOR A PURPA CONTRACT TERM OF FIVE YEARS OR LESS. IF CONTRACT LENGTH WERE ONLY FIVE YEARS OR SHORTER, IS IT YOUR OPINION THAT A QF PROJECT COULD RELY ON THE CONTRACT TO FINANCE THE DEVELOPMENT?

A. No. The "Enron meltdown" provided an Idaho example of the impact of shortening the term of QF contracts to five years. As the Commission noted when increasing the term limit from five years to 20 years (after reducing them earlier), only one PURPA contract was signed in Idaho with the shortened contract length. At that time, the Commission explained,

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[3] *IPUC Staff Comments*, IPUC Docket No. IPC-E-09-34, pp. 13-14 (filed May 3, 2010).

This Commission also cannot ignore the fact that since reducing the eligibility threshold to 1 MW and contract term to 5 years, there has been only one PURPA contract signed in Idaho. A longer contract, we find, better coincides with the amortization period or planned resource life of the renewable or cogeneration resources being offered, better reflects the amortization period of generation projects constructed by the utilities themselves and will coincidently provide a revenue stream that will facilitate the financing of QF projects.[4]

Q. DOES THE IDAHO COMMISSION LIMIT UTILITY-OWNED GENERATION RESOURCES TO A FIVE-YEAR TERM FOR COST RECOVERY OF THE INVESTMENT?

A. No. Any utility-owned resources of any significance that I am familiar with are approved by the Commission with terms in some cases up to 50 years, and are seldom shorter than 20. Of course, for a utility-owned resource the ratepayer is on the hook for providing the utility with a return both of and on the investment for the facility once it is put into rate base. Treating PURPA resources on an equal footing with utility-owned resources would mandate they also should receive longer-term contracts.

Q. FERC ALSO REFERENCED "LONG TERM CONTRACTS." IF YOU WERE TO ASSUME THAT PURPA REQUIRES A LONG-TERM CONTRACT, IN YOUR OPINION, IS FIVE YEARS A LONG TERM IN THE CONTEXT OF A UTILITY-SCALE CAPITAL INVESTMENT?

A. No. When considering financing significant capital investments, such as utility generation plants, "long-term contracts" would certainly mean more than five years.

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[4] IPUC Order No. 29029, at p. 7.

Q. IF I WERE TO TELL YOU THAT FERC'S RULES REQUIRE THE COMMISSION TO IMPLEMENT LONG-TERM, FIXED AVOIDED COST RATES THAT PREVENT THE UTILITY FROM CIRCUMVENTING THE NEED TO PAY FOR THE QF'S CAPACITY OR THAT ARE OF SUFFICIENT LENGTH TO SUPPORT INVESTMENT IN A UTILITY GENERATION FACILITY, IS IT YOUR OPINION THAT A FIVE-YEAR CONTRACT TERM MEETS THAT TEST?

A. No. Using such an unreasonably overbroad approach of shorting the contract length so that QFs cannot obtain financing is a way around FERC's rules. Developing accurate avoided cost pricing is a more rational approach that meets FERC's regulations.

Q. HAS THE IDAHO COMMISSION ITSELF MADE FINDINGS REGARDING THE LENGTH OF CONTRACTS WITH A FIXED RATE THAT IS NECESSARY TO ENCOURAGE QF DEVELOPMENT AND SUPPORT FINANCING FOR A QF PROJECT?

A. Yes. Just a few years ago, the Idaho Commission found:

> *We find that a 20-year contract length, along with other factors, has been beneficial in encouraging PURPA development in Idaho. We continue to believe that 20-year contracts better coincide with the useful life of the renewable/cogeneration resources. While it is not this Commission's responsibility to ensure a contract length that allows a QF to obtain financing, we find that reducing maximum contract length to five years would unduly hinder PURPA development. That is not the Commission's objective. We believe that, by utilizing other tools to ensure an accurate and up-to-date avoided cost valuation,*

we can continue to encourage the types of projects that were envisioned by PURPA while maintaining the transparency for ratepayers as PURPA requires. Therefore, we find that a maximum contract length of 20 years is appropriate. The parties to a power purchase agreement are free to negotiate a shorter contract if that would be most suitable for the project. As in the past, this Commission will consider contracts of more than 20 years on a case-by-case basis.[5]

Q. THE COMMISSION STATED, "WE FIND THAT REDUCING MAXIMUM CONTRACT LENGTH TO FIVE YEARS WOULD UNDULY HINDER PURPA DEVELOPMENT." DO YOU AGREE?

A. Yes, I believe Commission is correct. Real world economics dictate that a project will not get financing with a contract length of five years unless the investment has a five-year pay-back period. A five-year pay-back is far shorter than generally understood to be necessary for long-term utility-scale investments.

Q. HAVE CONDITIONS CHANGED SINCE 2012 WHEN THE COMMISSION STATED THAT REDUCING THE CONTRACT LENGTH WOULD UNDULY HINDER PURPA DEVELOPMENT?

A. No. The length of the QF contract has to do with the ability to obtain funds in order to build the project. Those conditions have not changed. The utilities' avoided costs may have changed and that should be the determining factor in whether projects are developed, rather than an arbitrarily short contract term that is designed to deprive financing and capacity payments to the QF.

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[5] IPUC Order No. 32697, at p. 24.

Q. ARE 20-YEAR CONTRACT TERMS OUT OF THE ORDINARY FOR ELECTRIC UTILITIES?

A. Not at all. For example, according to Idaho Power's most recent 10-K filing, in April of 2012 Idaho Power issued $75 million in first mortgage bonds that mature after 30 years. Long-term financial commitments are routine in all utilities' financing and planning.

Q. DR. READING, WHAT PRECIPITATED THE CONSOLIDATION OF PETITIONS FILED BY THE THREE UTILITIES IN THIS DOCKET?

A. Idaho Power filed a petition on January 30, 2015, to reduce the length of PURPA contracts to two years. The Commission granted the Company interim relief temporarily reducing QF contracts from 20 years to five years. On February 27, 2015, Avista petitioned the Commission for the same temporary and permanent relief that would be granted to Idaho Power and a five-year contract length for wind and solar QFs. Four days later on March 2, 2015, Rocky Mountain Power filed its petition seeking the same interim relief and a permanent reduction in the length of QF contracts to three years, along with an adjustment in the method of calculating avoided costs. The Commission consolidated the three cases into a single docket. I will discuss each of the utilities' petitions.

Q. COULD YOU PLEASE TELL US IDAHO POWER'S REASON FOR FILING THE ORGINAL PETITION FOR THIS CASE?

A. According to the Company's petition, it faces what some have called a "tsunami" of wind and solar PURPA projects washing over Idaho Power's system.[6] Idaho Power proposes to limit contract terms for all QFs eligible for IRP methodology rates to two years.

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[6] *Idaho Power's Petition*, IPUC Case No. IPC-E-15-01, p. 21.

Q. **WHAT IS IDAHO POWER'S RATIONALE FOR LIMITING PURPA PROJECTS TO ONLY TWO YEARS IN DURATION?**

Idaho Power's claim is that PURPA is imposing "risk" and "harm" to ratepayers. Idaho Power's petition largely discusses a problem with intermittent wind and solar QFs that have the capability of creating an oversupply problem on Idaho Power's system during certain periods of the year. According to Idaho Power's subsequent pleadings, the problem is not just intermittent wind and solar projects but PURPA itself in obligating ratepayers to the Commission-approved rates for a 20-year period.[7] In an attempt to prove its case, Idaho Power provides "examples" of the price paid for PURPA generation. Idaho Power claims customers must purchase power at these higher PURPA prices when the power is not needed to serve load or can be obtained in the market at a cheaper price.

Q. **DO YOU BELIEVE IDAHO POWER MAKES A COMPELLING ARGUMENT WHEN PRESENTING ITS EVIDENCE?**

A. No. Idaho Power arrives at its conclusions by only telling half of the story. When valid comparable evidence is presented, it shows the Company's own generating resources commit the same "sins" as the PURPA resources that they are asking the Commission to discourage.

Q. **COULD YOU PLEASE EXPLAIN WHAT YOU MEAN BY ONLY PRESENTING HALF THE STORY?**

A. The first half of the story is told when comparing the cost of PURPA resources to Mid-Columbia (Mid-C) prices. As shown in Exhibit No. 10 of Company witness Allphin's

[7] *Idaho Power's Answer to Simplot/Clearwater Joint/Cross Petition*, IPUC Case No. IPC-E-15-01, at p. 2 (filed March 19, 2015).

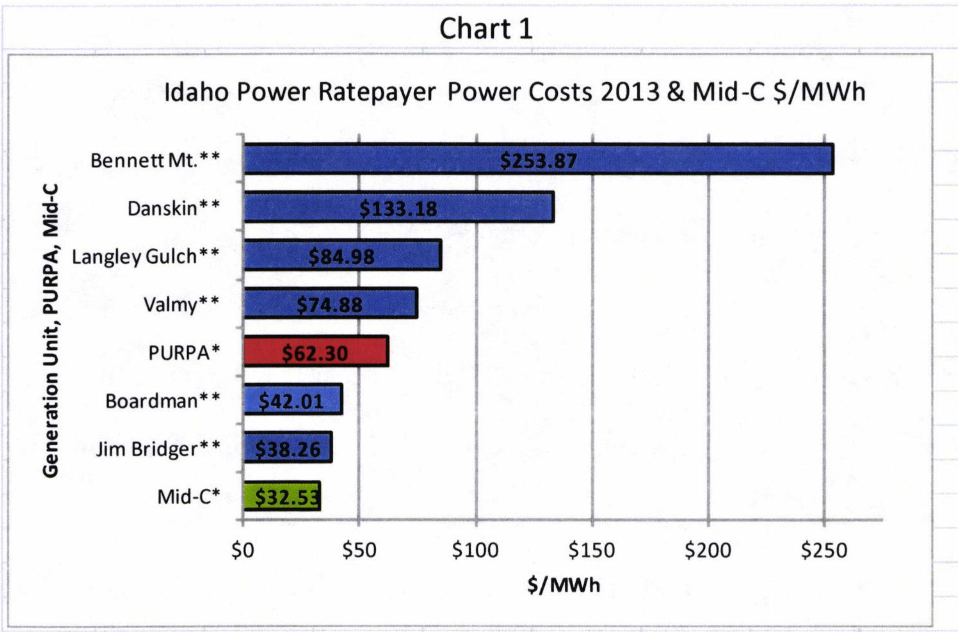
direct testimony, historical Mid-C prices have been lower than PURPA prices since 2002 to the present and are projected by Idaho Power to be lower over the next 20 years. What this comparison fails to recognize is capital costs are included in the PURPA per MWh price. Mid-C prices are market prices and are more reasonably related to the variable running costs of existing generating resources that do not contain capital costs. Both variable and capital costs are rolled together in the rates customers pay. When a utility's generating resource is approved in rate base, the ratepayers are "forced" to pay the capital costs of the resource over the approved life, even when the Company's own generating resources are not needed to serve load.

Q. WHAT DO YOU CONSIDER A MORE APPROPRIATE CAMPARISON?

A. The cost of PURPA resources paid by Idaho Power are passed through to customers in the retail rates customers pay. PURPA rates should be compared to what Idaho Power's customers pay for power from the Company's own generation facilities, which would include the rate based capital costs along with the fixed and variable running costs.

Q. HAVE YOU MADE THAT COMPARISON WHERE BOTH PURPA PROJECTS AND IDAHO POWER'S GENERATING RESOURCES ARE MEASURED ON AN EQUIVALENT BASIS?

A. Yes, a reasonable comparison can be made by using Idaho Power's FERC Form 1 data for production costs and Idaho Power's Responses to Simplot's discovery request for the capital portion of the costs. Chart 1 below displays the results of including the estimated capital costs along with the variable running costs of Idaho Power's generating facilities on a per MWh basis for 2013, therefore comparing them on an equivalent basis to the PURPA costs in retail rates. For 2013, as expected, the market Mid-C prices are the lowest cost non-hydro resource on Idaho Power's system. Two of the Company's coal resources have a lower cost than PURPA resources with the other four thermal units at a higher cost. This does not take into account the additional costs that might be necessary for coal plant upgrades for environmental compliance for the Company's non-PURPA resources that may be necessary in the near future.



Source:
* R. Allphin Exhibit 10
** Attachment 2 - Response to Simplot's Request No. 13, 2013; 'Net Plant' * .18 for Capacity; Response to Simplot's Request No. 5(d), annual reveune requirement is 18% of capital Cost; Production Expense' and 'Net Generation', 2013 FERC Form 1

Q. DR. READING, I DO NOT SEE IDAHO POWER'S HYDRO RESOURCES IN YOUR CHART 1. SINCE, DEPENDING ON STREAM FLOWS, IDAHO POWER'S HYDRO RESOURCES MAKE UP HALF OF THE COMPANY'S ENERGY SUPPLY, WHY HAVE YOU EXCLUDED THEM FROM YOUR COST COMPARISONS?

A. Idaho Power's hydro facilities are certainly the Company's lowest cost resource with a depreciated rate base and very low variable running cost. Also, depending on stream flow conditions the capacity factors will vary significantly from year to year, and that would in turn cause the cost on a per MWh basis to also vary significantly. So the year picked for the analysis could be misleading. Due the above factors I felt looking at thermal resources along with the market price would be a more reasonable comparison.

Q. ARE THERE ANY OTHER REASONS TO EXCLUDE HYDRO RESOURCES FROM YOUR ANALYSIS?

A. Yes. Idaho Power has been in the process of relicensing its Hells Canyon Complex ("HCC") for well over a decade. It appears that the capital and variable costs associated with the massive environmental remediation associated with that relicensing will dramatically change the economics of the Company's hydro resources as a whole – and not just the costs associated with the HCC. The final cost of relicensing HCC won't be known for years; therefore it would be speculative for me to include the unknowable increased costs of the Company's hydro resources in my analysis.

Q. DO THE OTHER TWO UTILITIES IN THIS CASE SUPPORT COMPARING THE PRICE OF PURPA RESOURCES TO THE MID-C PRICES THAT DO NOT INCLUDE THE CONSIDERATION OF CAPACITY COSTS?

A. I don't know about Avista, but PacifiCorp has stated in Washington Utilities and Transportation Commission (WUTC) cases that it is inappropriate to make the comparison of PURPA resources with the Mid-C market prices. I have provided as Exhibit No. 204 excerpts of the testimony of Gregory Duvall before the WUTC in recent general rate cases. PacifiCorp witness Gregory Duvall states, *The inclusion of capacity payments in avoided costs indicates that market prices alone are not equivalent to avoided cost prices.*[8]

And the same PacifiCorp witness in a later WUTC docket stated,

If avoided cost prices are greater than market prices years after the PPA was signed, it does not mean that the avoided cost prices in the QF PPA are excessive or otherwise violate PURPA's strict requirements.

PURPA requires that the prices paid to QFs be equal to a utility's avoided cost of energy and capacity. Each state has an approved method for calculating these avoided costs, and the resulting prices are heavily scrutinized and ultimately approved by the respective regulatory commissions. The avoided cost calculation is intended to ensure that customers are indifferent to QF generation, i.e., that the price paid to the QF is the same as the price the utility would otherwise incur if it was generating the electricity itself. Comparing QF PPA prices for a single test year to the variable cost of market purchases or the Company's existing resources is insufficient to determine whether QF prices are reasonable and prudent from a ratemaking standpoint.[9]

Subsequently, Mr. Duvall further testified:

First, simply relying on market prices does not reflect Pacific Power's actual avoided costs as determined by the Commission because it fails to account for the impact of a QF on the Company's existing resources or the QF's ability to defer

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[8] Exhibit No. 204 at 11 (containing the Rebuttal Testimony of Gregory Duvall, WUTC Docket UE-130043, August 2, 2013, p. 22).

[9] Exhibit No. 204 at 17 (containing Direct Testimony of Gregory Duvall, WUTC Dockets UE-140762, -140617, -131384, -140094, May, 2014, p. 11).

future capacity additions. PURPA requires the Company to purchase energy and capacity made available by QFs.[10]

As PacifiCorp's witness, Mr. Duvall testifies in its Washington jurisdiction that comparing market prices to PURPA resource prices is inappropriate and misleading.

Q. IDAHO POWER CLAIMS THAT RATEPAYERS ARE HARMED WHEN THE COMPANY IS FORCED TO PURCHASE PURPA POWER WHEN IT IS NOT NEEDED. DO YOU AGREE?

A. No more or less than when ratepayers are "forced" to pay for the utilities' own generating resources when they are not needed. Company witness Allphin presents a series of 24 separate graphs in his Exhibit No. 6 for the first week of each month for the years 2016 and 2017. Each graph displays, on an hourly basis, total system load along with the Company's "must-run" resources, "must-take" non-PURPA PPA's, along with "must-take" PURPA resources. The "must-run" Company-owned facilities are their hydro and coal generation units at their minimum operational levels that cannot be backed down further for environmental reasons for hydro resources, or shut down for coal generation units. Market purchases and sales are excluded from the Exhibit's graphs.

Q. WHAT IS THE IDAHO POWER WITNESS ATTEMPTING TO DEMONSTRATE WITH THE SERIES OF 24 GRAPHS?

A. Again, Idaho Power is telling only half of the story. According to Mr. Allphin's testimony,

This analysis shows the frequency with which Idaho Power's system, when in a state where it cannot be backed down any further, will have generation resources

[10] Exhibit No. 204 at 25-26 (containing Rebuttal Testimony of Gregory Duvall, WUTC Dockets UE-140762, -140617, -131384, -140094, November, 2014, pp. 14-15).

in excess of its system load. This will put the system into an imbalanced, over-generation state unless some remedial actions are taken to balance the system. If remedial actions are not available, or not employed in a timely manner, then the Company can have system reliability violations, events, and/or outages and damage.[11]

An examination of the monthly graphs over the two-year period indicates, as one would expect, a mix of relationships among the Company's load patterns over the 24 months considered, and the output of the power supply depicted, indicating both an over and under supply of power in various months.

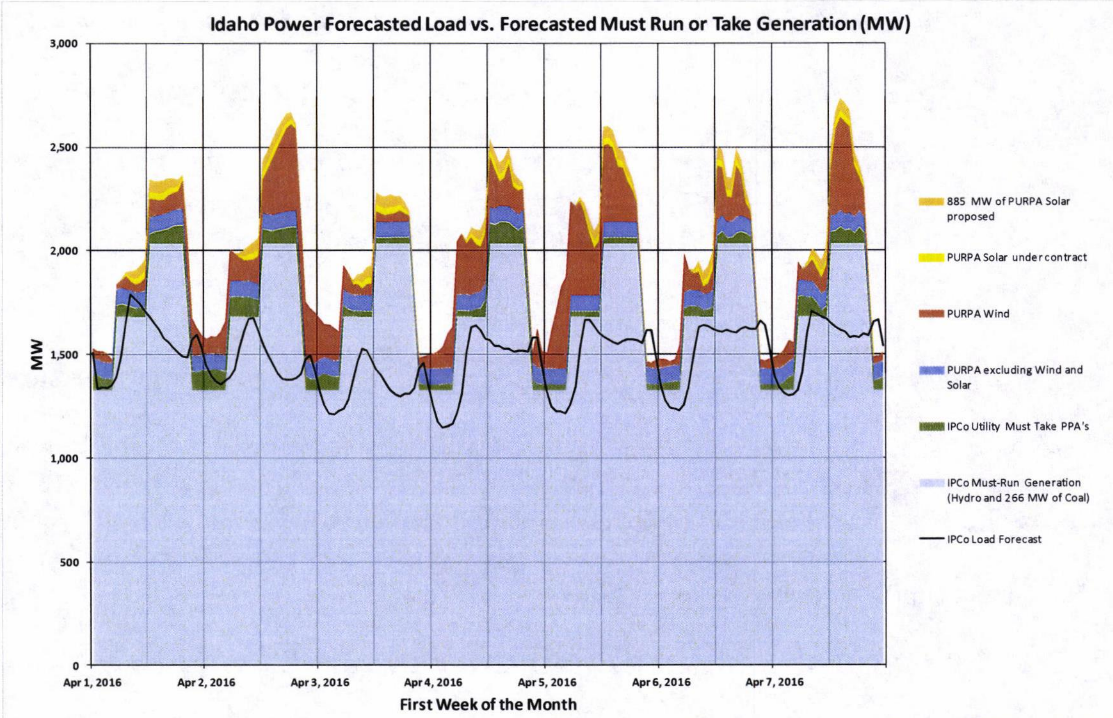
Q. COULD YOU BE MORE SPECIFIC AND PROVIDE EXAMPLES FOR THE 24 GRAPHS THAT INDICATE THE OVER AND UNDER SUPPLY OF POWER ON IDAHO POWER'S SYSTEM RELATIVE TO THE SYSTEMS LOADS?

A. I have selected two months as examples that are at the ends of the spectrum of when the graphs indicate first an oversupply relative to loads and second when the situation is reversed and there is an undersupply. The two example months are April and August of 2016 and indicate there are times when both the Company-owned resources and PURPA power contribute to filling part of the gap when output is less than load and other times when the Company's own "must-run" resources alone are producing power greater than system load needs.

Q. COULD YOU PLEASE EXPLAIN WHAT YOU MEAN USING THE APRIL 2016 GRAPH FOUND ON PAGE 5 OF 12 OF MR. ALLPHIN'S EXHIBIT NO. 6?

A. Below is copy of the April 2016 Graph included in Mr. Allphin's testimony.

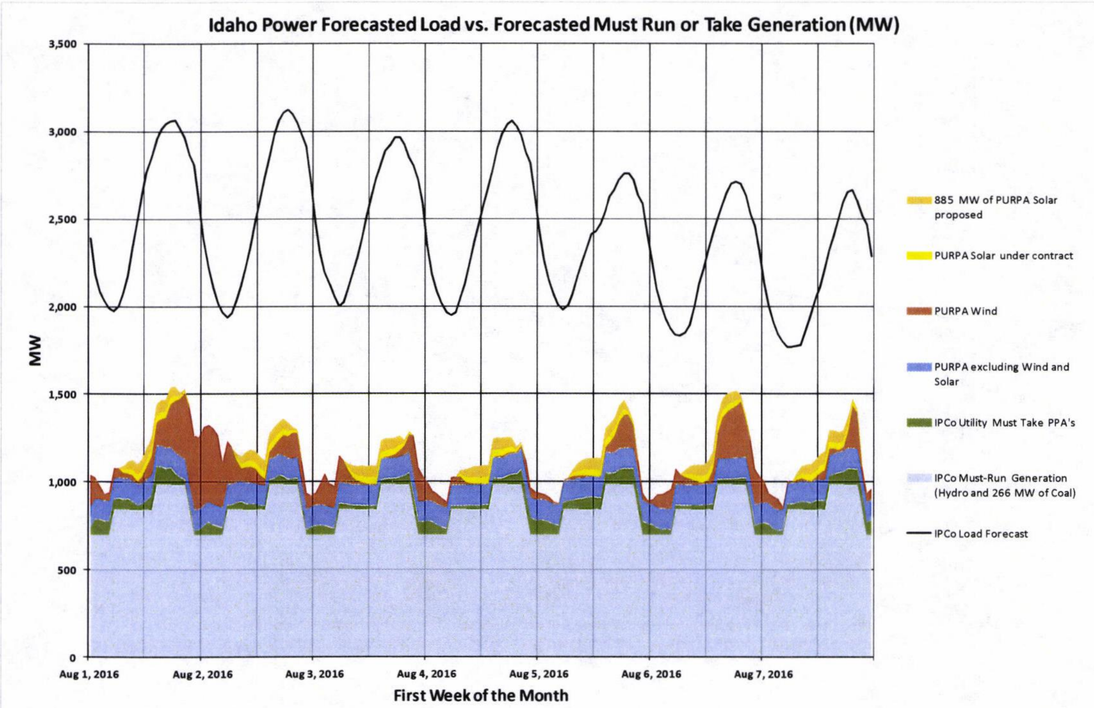
[11] Direct Testimony of Randy Allphin, Idaho Power, IPUC Case No. IPC-E-15-01, pp. 9-10.



As can be seen in the above graph for April, when loads are relatively low, system loads are less than both the "must run" Idaho Power generation units as well as PURPA resources. This would mean that Idaho Power's "must run" units are contributing alone to the "system reliability violations, events, and/or outages and damage" unless remedial action is taken in a timely manner, even if there is no PURPA power being produced.

Q. COULD YOU PLEASE EXPLAIN THE OTHER END OF THE SPECTURM, AUGUST 2016 WHEN BOTH IDAHO POWER'S RESOURCES AT "MUST-RUN" AND PURPA RESOUSES ARE NOT SUFFICIENT TO MEET THE SYSTEMS LOADS?

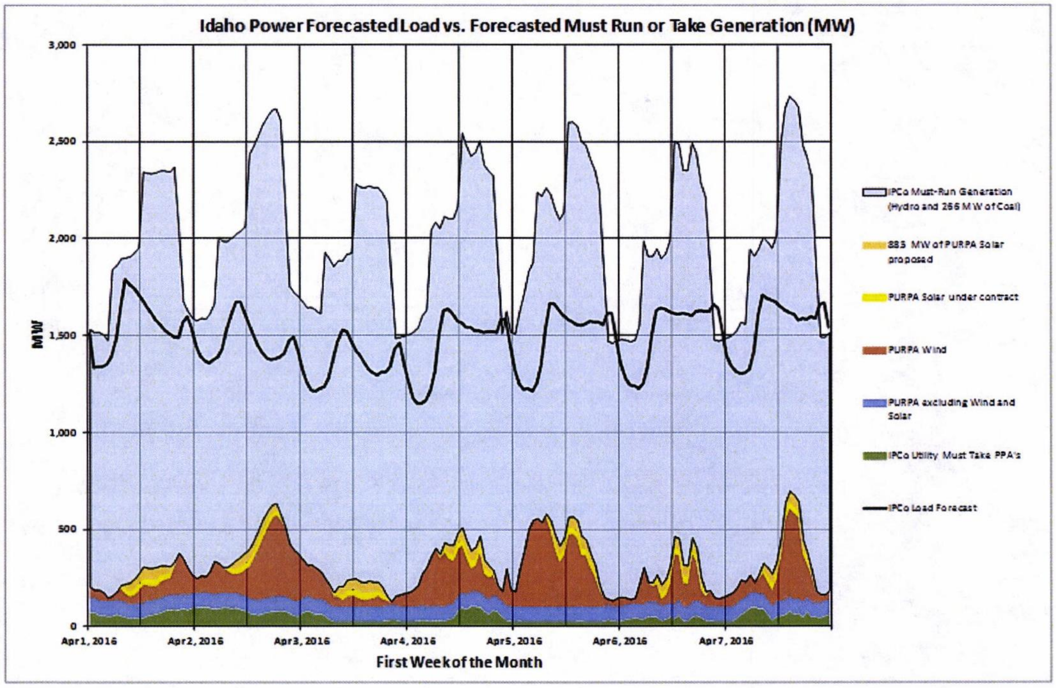
A. As can be seen below in a copy of Mr. Allphin's graph for August 2016, that is predicted to be a relativity high load month. In this graph, Idaho Power's "must run" resources and PURPA are significantly below system loads.



This means PURPA generation is contributing to the Company's system load demands just as Idaho Power's Company-owned resources are. The other monthly first week graphs display a mix of over and under generation during certain hours over the first week of each month.

Q. DO YOU HAVE ANY ADDITIONAL OBSERVATIONS ABOUT IDAHO POWER'S EXHIBIT NO. 6?

Yes, for the casual observer, since PURPA, other PPAs and Company-owned resources are all defined as "must run" in the Exhibit No. 6, PURPA could just as easily be displayed along the horizontal axis first with the utility-owned resources on top. This could lead one to assume the Company-owned resources are the problem of Idaho Power being "forced" to receive power when it is not needed, not PURPA resources. The graph below uses the same data for April 2016 as used by in Exhibit No. 6 and only reorders how the resources are displayed in the graph.



As can be seen, reversing the display of the various resources causes it to appear that Idaho Power's "must-run" resources are the source of oversupply, not PURPA. In truth, all of the resources are all part of the same power supply system and contribute to over and undersupply at any point in time.

Q. ARE YOU IMPLYING THAT COMPANY-OWNED RESOURCES AND PURPA RESOUCES ARE THE SAME THING?

A. No. There are important differences depending on the type of resource, and both impose different risks and provide benefits for ratepayers under different load and resource and power market conditions. The off-system price of power is currently relatively low, and the Northwest currently has a surplus of power. However, history shows that power market prices in the Northwest have been volatile and power surpluses and deficits can change quickly. One thing that is certain is there will be ups and downs in the future, and the current situation will not stay the same as today over the next 20 years.

Q. CAN YOU PROVIDE AN EXAMPLE OF WHAT YOU MEAN BY SAYING THERE CAN SOMETIMES BE RAPID CHANGES IN POWER MARKETS?

A. The most dramatic swing in market prices for power in the Northwest in the recent past is the so-called "Enron meltdown" when Mid-C prices got as high as $677 per MWh in June of 2000 on a daily basis.[12] At the same time, due to a variety of causes, utilities were facing power shortages. With the then-dramatic swings as background, the Commission issued Order No. 29029 quoted above and increased the length of PURPA contracts to 20 years from five years and raised the eligibility cap for published rates.[13]

Q. WHAT OTHER ACTIONS DID THE COMMISSION UNDERTAKE IN THIS VOLATILE MARKET TIME FRAME?

A. The Commission, in July of 2001, approved a Certificate of Public Convenience and Necessity (CPCN) for Idaho Power's peaking facility, the Mountain Home Generation Station (Danskin). In its decision the Commission said,

> *We note that the procedure followed in this case has limited the type and extent of review that would otherwise occur in a certificate filing. The price of power on the spot market, the shortage of water for hydro generation and the Company's projected inability to serve native load requirements with Company generation and contract supplies have all joined to create the unique factual situation presented and have also fashioned the particular regulatory treatment requested by the Company.*

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[12] https://www..nwcouncil.org.Appendix_C__Electricity_Price_Forecast_.pdf.

[13] IPUC Order No. 29029, at p. 7.

> *We are convinced that the volatility of the electric spot market created a situation that justified a deviation from the Company's 2000 IRP and its actions in developing plans for the Mountain Home Station.*[14]

Faced with the upheaval in the power markets at this time, the Commission reacted by increasing the length of PURPA contracts to 20 years and approving a peaking plant that was not included in Idaho Power's Near-Term Action Plan in its 2000 IRP. The point of the above example is that over a time period of a just a few years unforeseen circumstances can significantly impact market conditions for both supply and price. Current power market conditions today have no guarantee they will remain the same over a 20-year period.

Q. COULD YOU PLEASE EXPLAIN FURTHER WHAT YOU MEAN BY SAYING BOTH UTILITY-OWNED RESOURCES AND PURPA RESOURCES HAVE DIFFERENT RISKS AND BENEFITS FOR RATEPAYERS?

A. Utility-owned resources and PURPA supply costs impact ratepayers in different ways. A PURPA project will only get paid when it supplies power to the utility. On the other hand, with a rate-based, utility-owned resource, the capital portion of the plant is rolled in customer rates even if the facility is idle. This means for a utility-owned resource the capacity costs are factored into retail rates on a per-MWh basis, and they can vary significantly as the capacity costs of the facility are spread over higher and lower power output. For a PURPA resource, the capital portion of the price is included in the levelized dollars per MWh, and ratepayers are charged only when the facility provides power.

[14] IPUC Order No. 28773, at pp. 11-12.

Idaho Power says it is concerned that as QF contracts get longer there is increased risk and potential harm to ratepayers, without recognizing their own resources lock in ratepayers as well to pay for their own generating resources. The Commission Staff asked Idaho Power;

REQUEST NO. 18: On page 22, the Petition states that ". . . the risk and potential harm increases, the longer the price estimates are locked in." Does Idaho Power believe long-term, locked-in price estimates could potentially benefit Idaho Power in some circumstances?

RESPONSE TO REQUEST NO. 18: No.[15]

What Idaho Power is failing to acknowledge is that their own plants are also "locked in" for ratepayers for the plant life that is 20 or more years.

Q. DOES THIS EXAMPLE DEMONSTRATE ANY OTHER POINTS?

The above example also points out that PURPA projects, even those with 20-year contracts, do provide a risk hedge and a benefit to ratepayers. PacifiCorp's witness Mr. Duvall agrees with this point and has testified at length before the Washington Commission regarding the extensive benefits of PURPA projects:

In addition to providing the capacity benefits discussed above, the out-of-state QFs provide significant benefits because they are renewable, emission-free generators.

* * * *

Emission-free resources may act as a hedge against future carbon regulation, the exact nature of which is currently unknown. In fact, the

[15] Idaho Power's Response to IPUC Staff Production Request No. 18.

Commission has acknowledged that future carbon regulation may have a significant impact on the Company's operations. The out-of-state QFs, like all of the Company's renewable resources, will help to mitigate that impact.[16]

Q. ARE THERE OTHER WAYS THAT PURPA POWER PROJECTS CAN LOWER RISKS FOR RATEPAYERS THAT UTILITY-OWNED RESOURCES DON'T?

A. In addition to not requiring ratepayers to pay for the capital portion of undelivered electricity, PURPA resources avoid the fuel cost risks ratepayers face from a utility's own resources. All three utilities that are part of this case have some form of a power cost adjustment mechanism that, on an annual basis, allows them to recover the majority of their net power supply expenses. This means the utility is able to pass onto ratepayers any fluctuations in the costs of their fuel supplies so that it is the ratepayer, not the utility, that assumes the risk.

Q. THE THREE INVESTOR OWNED UTILITIES ALL ARE PROPOSING TO SHORTEN THE CONTRACT LENGTH FOR ALL PURPA PROJECTS ABOVE THE ELIGIBILITY RATE CAP, IDAHO POWER FOR TWO YEARS AND ROCKY MOUNTAIN POWER THREE YEARS. AVISTA RECOMMENDS FIVE YEARS AND BELIEVES IF A VERY FAVORABLE OPPORTUNITY WAS PRESENTED TO THE UTILITY IT SHOULD HAVE AN OPTION FOR A LONGER CONTRACT.[17] DO YOU AGREE WITH THE RECOMMENDATIONS OF THE UTILITIES?

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[16] Exhibit No. 204 at 28-29 (containing Rebuttal Testimony of Gregory Duvall, WUTC Dockets UE-140762, -140617, -131384, -140094, November, 2014, pp. 17-18).

[17] Direct Testimony of Clint Kalich, Avista Corporation, February 27, 2015, AVU-E-15-01, p. 3.

A. The Companies are advocating an unreasonably overbroad approach by treating all types of PURPA resources the same. Limiting the contract length will cause all types of PURPA projects to become uneconomic due to the inability to obtain financing, not just "wind and solar." The Idaho Commission has established precedent for setting different terms and conditions for different types of PURPA projects.

Recently, in Case No. GNR-E-10-04 the Commission lowered the eligibility cap for wind and solar to 100 kW while leaving the higher 10 average monthly MW cap for all other project types. The Commission's rationale for doing so was that wind and solar resources have unique characteristics not found in other types of PURPA QFs.

> *Based upon the record, the Commission finds that a convincing case has been made to temporarily reduce the eligibility cap for published avoided cost rates from 10 aMW to 100 kW for wind and solar only while the Commission further investigates the implications of disaggregated QF projects. We maintain the eligibility cap at 10aMW for QF projects other than wind and solar (including but not limited to biomass, small hydro, cogeneration, geothermal, and waste-to-energy). The Petitioners have not convinced us that lowering the eligibility cap for these other QF technologies is necessary or in the public interest.*
>
> *Wind and solar resources present unique characteristics that differentiate them from other PURPA QFs. Wind and solar generation, integration, capacity and ability to disaggregate provide a basis for distinguishing the eligibility cap for wind and solar from other resources.*[18]

[18] IPUC Order No. 32176, at p. 9.

Currently, the three utilities have posted different published avoided cost rates for different resource types. Each of the utilities recognizes QFs have different defining characteristics.

Q. BOTH CLEARWATER AND SIMPLOT CURRENTLY HAVE COGENERATION PROJECTS. DO YOU BELIEVE THEY HAVE CHARACTERISTICS THAT DISTINGUISH THEM FROM WIND AND SOLAR AS WELL AS OTHER PROJECTS?

A. Cogeneration projects have "unique characteristics" that are distinct from other types of PURPA projects. They are more fuel efficient than traditional generation and support a stronger economy. FERC defines a cogeneration facility as,

> *A cogeneration facility is a generating facility that sequentially produces electricity and another form of useful thermal energy (such as heat or steam) in a way that is more efficient than the separate production of both forms of energy. For example, in addition to the production of electricity, large cogeneration facilities might provide steam for industrial uses in facilities such as paper mills, refineries, or factories, or for HVAC applications in commercial or residential buildings.*[19]

FERC regulations also exempt cogeneration QFs from the 80 MW cap imposed on other types of qualifying facilities, and FERC has stated that,

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[19] http://www.ferc.gov/industries/electric/gen-info/qual-fac/what-is.asp

> *Cogeneration facilities can use significantly less fuel to produce electric energy and steam (or other forms of energy) than would be needed to produce the two separately.*[20]

According to an Iowa State University doctoral dissertation,

> *Cogeneration has a fuel efficiency of 80% to 90 % compared to the 33% fuel efficiency of conventional electricity generation units.*[21]

Q. YOU STATED ABOVE THAT COGENERATION SUPPORTS A STRONGER ECONOMY. WHY DO YOU SAY THAT?

A. Cogeneration supports the economic viability of Idaho industrial facilities. While this is not linked directly to a utility's avoided cost, it contributes to the strength of Idaho's economy and employment, which in turn helps make a stronger utility. Also, cogeneration facilities produce electric power without using additional fuel or contributing additional pollution, which also benefits society. Cogeneration represents one of the most effective approaches to energy conservation, because it produces two types of energy at once – electric power and thermal energy. Conventional thermal power generators typically range from 33% to 60% efficient, with coal plants in the lower end of the range and combined cycle gas plants in the upper range. They essentially waste between 40% to 67% of the fuel energy -- whereas cogeneration facilities can achieve efficiencies of 80%. On top of that, cogeneration facilities make the host manufacturing plant more financially secure with all the attendant societal benefits

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[20] FERC Order 688, Docket RM06-010, at p. 14 (Oct. 20, 2006).

[21] The Economic and Environmental Performance of Cogeneration under the Public Utility Regulatory Policies Act, Daniel, Shantha E., Iowa State University, 2009, p. 4.

of having a more robust economy. Cogeneration also significantly reduces carbon emissions, reduces business costs, relieves grid congestion and improves energy security.

Q. ARE THERE OTHER CONSIDERATIONS RELATED TO THE BENEFITS OF COGENERATION IN THE CONTEXT OF THIS PARTICULAR CASE?

A. Yes. As I noted earlier, Idaho Power's petition primarily points to a problem of oversupply of generation that is occurring during certain times of the year as a result of intermittent and relatively unpredictable PURPA output from wind and solar projects. Cogeneration QFs are base-load resources that do not provide intermittent deliveries, and their output should be more easily predicted and managed during these over-supply periods.

Q. WHAT IS THE POSITION OF THE THREE UTILITIES RELATING TO THE PURPA PROJECTS PROPOSED IN THEIR RESPECTIVE SERVICE TERRITORIES?

A. The perceived "flood" of PURPA projects varies among the three utilities. Idaho Power states the Company currently has 461 MW of PURPA solar capacity under contract with an additional 885 MW in the queue actively seeking power sales agreements.[22] Rocky Mountain Power states it has had an "exponential increase in PURPA contract requests" consisting of 97 projects totaling 1,553 MW in the last two years throughout its multi-state system.[23]

Q. WHAT IS AVISTA'S POSITION WITH REGARD TO QFS SEEKING PURPA CONTRACTS IN ITS SERVICE TERRITORY?

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[22] *Idaho Power's Petition*, IPUC Case No. IPC-E-15-01, p. 18.

[23] *Rocky Mountain Power's Petition*, IPUC Case No. PAC-E-15-03, p. 19.

A. While Avista is not claiming there is a torrent of PURPA projects in its service territory, its concern is if a neighboring utility such as Idaho Power offers only five-year contacts "sophisticated and motivated PURPA developers" will seek longer term contracts by wheeling the QF output to Avista.[24] Avista advocates for the ability to contract for PURPA projects with terms longer than five years in the event of a very favorable PURPA opportunity.[25] Avista, however, does not offer specifics on what a "very favorable PURPA opportunity" means, and it does not state that it supports continuing 20-year QF contracts for projects subject to the IRP methodology.

Q. DO YOU AGREE WITH AVISTA'S POSITION THAT UTILITIES SHOULD BE ALLOWED TO NEGOTIATE A TERM LONGER THAN THE COMMISSION-AUTHORIZED TERM?

A. Yes. Under the Commission's long-standing rules, utilities have always been allowed to negotiate a term longer than the Commission-approved contract length. I agree that regardless of the outcome of this proceeding the utility and the QF should be allowed to agree to a longer term under the appropriate circumstances.

Q. DOES AVISTA PROVIDE ANY EVIDENCE THAT ANY QFS HAVE TRIED TO WHEEL THEIR OUTPUT TO SELL IT TO AVISTA, GIVEN THE OVERSUPPLY PROBLEM ON IDAHO POWER'S SYSTEM?

A. No. Avista provides no evidence any QF has tried to wheel its power to Avista to sell to it from off-system. Avista only points to a single QF, operated by Kootenai Electric Cooperative, Inc., that sought to wheel its output *away* from Avista and to Idaho Power.

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[24] Direct Testimony of Clint Kalich, Avista Corporation, IPUC Case No. AVU-E-15-01, p.5.

[25] *Id.* at pp. 2-3.

Q. DOES AVISTA PROVIDE ANY REASON TO BELIEVE THAT THE LARGE NUMBER OF PROSPECTIVE SOLAR QFS DISCUSSED IN IDAHO POWER'S PETITION MAY SEEK TO SELL TO AVISTA INSTEAD?

A. No. Avista's avoided costs for solar resources are lower than Idaho Power's avoided costs for solar resources because Avista has a different load profile that does not lend itself to high avoided costs for solar output. Avista's published rates for solar projects are currently set at $49.77 per MWh on a 20-year levelized basis for an online date in 2016, while Idaho Power's comparable rate for a 2016 online year is $66.85 per MWh. I would expect the IRP methodology rates may well be lower than the $49.77 per MWh amount, plus the off-system solar QF would need to pay to wheel the output to Avista. There is no reason to believe solar QFs would be able to rely on the economics of those low rates to finance a solar QF.

Q. IDAHO POWER, AS YOU POINTED OUT ABOVE, STATES IT HAS 461 MW OF PURPA SOLAR CAPACIY UNDER CONTRACT AND AN ADDITIONAL 885 MW IN THE QUEUE TO BE ON-LINE IN 2016. DO YOU HAVE AN OPINION AS TO THE PROBABILITY THAT ALL THOSE QF PROJECTS WILL ACTUALLY BE CONSTRUCTED?

A. In Response No. 2 to the Idaho Conservation League and Sierra Club's First Production Request Idaho Power stated,

> *As of the date of the response to this Request, 380 megawatts ("MW") of the 521 MW of QFs under contract, but not yet on-line, are in compliance with their respective agreements; therefore, Idaho Power has no reason to assume they will not come on-line as stated in their agreements. To date, 141 MW of the 521*

MW are not in compliance with their respective QF agreements and Idaho Power is taking the appropriate actions as allowed within those agreements.[26]

Based on a copy of a letter provided to me by the developer, Idaho Power has now terminated the four projects with 141 MW of capacity, Clark Solar 1 through 4. I have provided a copy of this letter as Exhibit No. 205. This means more than one-fourth of the capacity of the signed QF contracts due to come on line in 2016 have had their contracts terminated. At this point, the status of the others under contract is uncertain.

The projects that do not have executed contracts appear to be unlikely to ever obtain a contract or be developed in the near future. Under Idaho Power's Schedule 73, a developer must only provide basic project information in writing to receive indicative pricing, and must provide a few additional items, such as proof of site control over the property underlying the project, in order to obtain a draft contract. In response to Simplot Production Request No. 4, Idaho Power indicates, of the 48 PURPA projects that comprise the 885 MW in the queue requesting pricing or contracts, only one of the proposed projects has provided sufficient information to receive a draft energy sales agreement and 61% of the Idaho projects have failed to provide enough information to receive indicative pricing. Idaho Power has provided no documents supporting an assertion that most of these projects provided anything more than a simple inquiry through a telephone call.

In addition, if any of the solar projects fail to be on-line before the end of 2016, the investment tax credits for capital costs will drop from 30% to 10%. Thus, there is

[26] Idaho Power's Response to Idaho Conservation League/Sierra Club Production Request No. 4.

sufficient evidence to doubt that the volume of solar projects claimed by Idaho Power will actually be producing electricity by the end of 2016, if ever.

Q. ARE THERE OTHER ISSUES FOUND IN ANY OF THE UTILITIES' FILINGS?

A. Yes. Rocky Mountain Power proposes to change the IRP methodology to better respond to a large influx of QFs. Rocky Mountain Power stated they are seeking the Commission to approve,

> *Modification of the Company's avoided cost methodology such that preparation of indicative pricing for QFs reflects all active QF projects in the pricing queue ahead of any newly proposed QF requests for indicative pricing.*[27]

Q. DO YOU AGREE WITH ROCKY MOUNTAIN POWER THAT THE COMMISSION SHOULD CONSIDER REVISIONS TO THE AVOIDED COST PRICING METHODOLOGY?

A. Yes. For the reasons I will explain further below, it would be appropriate to address the avoided cost pricing methodology if the utilities have truly demonstrated that there is an oversupply problem. However, unlike Rocky Mountain Power, I believe that adjusting the pricing methodology to send accurate price signals is the only step that needs to be taken to rectify any problems with Idaho's implementation of PURPA.

Q. HAVE THERE BEEN SOME OTHER CHANGES IN THE METHOD TO FIND AVOIDED COST SINCE THE COMMISSION ISSUED ITS ORDER IN GNR-E-11-03, THE CASE THAT APPROVED THE CURRENT METHOD?

A. Yes. When Idaho Power filed with the Commission its PURPA contracts with Boise City Solar (IPC-E-14-20) and Grand View PV Solar Two (IPC-E-14-19) the Commission

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[27] *Rocky Mountain Power's Petition*, IPUC Case No. PAC-E-15-03, p. 4.

Staff filed Comments stating they were correcting some "errors" caused by the simplifying assumption in Idaho Power's single-run method approved by the Commission. Staff then recalculated the rates offered by Idaho Power for the two contracts.[28] The two projects decided to accept the lower rates based on Staff's methodological changes that were subsequently corrected by Idaho Power. Rocky Mountain Power's suggestion to update the resource stack more quickly to respond to large influxes of QFs may also be appropriate.

Q. IDAHO POWER ASSERTS THAT IT HAS AN OVER-SUPPLY PROBLEM DURING CERTAIN TIMES THAT CAUSES IT TO SELL PURPA POWER ON THE MARKET AT AN ECONOMIC LOSS. DO YOU KNOW OF OTHER ADJUSTMENTS TO THE AVOIDED COST METHODOLOGY THAT COULD POTENTIALLY BE EXAMINED?

A. Idaho Power is describing a situation where the actual avoided costs during certain time frames may be negative because the Company states it would incur an economic loss by accepting the QF power. The Commission's Staff Production Request No. 14 asked if Idaho Power's single-run IRP methodology accounts for such instances by assuming excess PURPA generation will be sold at a loss, and thus lower the overall average avoided cost over the term of the contract. The Company responded,

> *Within the Incremental Cost IRP Methodology (IRP methodology) the hourly price is assigned based on the highest increment cost displaceable generation resource operating in that hour. The displaceable resources being Idaho Power-owned generation, including any must-run limitations and Idaho Power market*

[28] *IPUC Staff Comments*, IPUC Case No. IPC-E-14-20, p. 5 (filed Oct. 31, 2014).

purchases. If there are no displaceable resources available in a specific hour, the energy rate is set to $0 in that hour. The methodology does not assume excess PURPA generation will be sold at a loss.[29]

Q. HOW DO YOU INTERPRET THE COMPANY'S RESPONSE?

A. Idaho Power indicated that the single-run methodology does not address the circumstance where the avoided costs are negative due to uneconomic off-system sales during the over-supply event, and instead assigns an avoided cost of zero when the actual avoided cost is negative.

Q. WHAT WOULD BE THE IMPACT OF CHANGING THE METHODOLOGY SO THAT IT COULD ACCOUNT FOR NEGATIVE AVOIDED COSTS?

A. The average avoided cost offered to the QF would incorporate these instances of negative avoided costs, and the instance of negative avoided costs would cause the overall average rate calculated over the term of the agreement to be lower.

Q. WHAT WOULD BE THE REAL-WORLD IMPACT OF A LOWER OVERALL AVOIDED COST ASSOCIATED WITH THE INSTANCES OF NEGATIVE AVOIDED COSTS?

A. The impact would be that the IRP methodology rates offered to prospective QFs would be lower. That lower price signal would, based on that QF's projected output profile, determine whether the project could be economically developed. In this example, I would expect that a lower avoided cost rate would have the impact of deterring PURPA development.

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[29] Idaho Power's Response to IPUC Staff's Production Request No. 18.

Q. IN YOUR OPINION, IS AN ACCURATE PRICE SIGNAL A BETTER WAY TO ADDRESS THE ALLEGED PURPA PROBLEM IDAHO POWER IDENTIFIED THAN A SHORTER CONTRACT TERM?

A. Yes.

Q. DO YOU HAVE ANY OTHER COMMENTS ON THE LIMITATIONS OF THE CURRENT SINGLE-RUN METHODOLOGY?

A. The prior double-run methodology would have accurately taken into account the instances where off-system sales caused the avoided costs to be negative, and in my opinion would send more accurate price signals.

Q. YOU HAVE JUST DISCUSSED POTENTIAL ADJUSTMENTS THAT HAVE BEEN MADE OR COULD BE MADE TO THE CALCULATION OF AVOIDED COSTS. ARE YOU RECOMMENDING ANY OF THESE CHANGES BE MADE AND APPROVED BY THE COMMISSION?

A. No, not without considering other potential adjustments to send accurate price signals. In a fully litigated case dealing with avoided cost methodologies, there would no doubt be changes to the method of calculating avoided costs that would cause resulting increases and decreases to QF prices offered by the utilities. What I am suggesting is that correct pricing should be used rather than an arbitrarily short contract length that will, on its own, discourage PURPA development. If the price is not sufficient to make a project profitable at the utility's avoided costs, the length of the contract is irrelevant and projects will not be built. The key is to properly price the avoided costs at the utility's avoided costs. This is what PURPA was intended to do and will only encourage projects when they meet a threshold price of the project being economical.

Q. **WHAT ARE YOUR RECOMMENDATIONS FOR THE COMMISSION?**

A. Because limiting the term of contracts to five years or less will essentially eliminate all types of PURPA projects including those that are environmentally sound, fuel efficient, and contribute to the economy of the state, I recommend the Commission maintain the current 20-year contract length for QFs eligible for the IRP methodology, or at a minimum for all non-intermittent QFs. If adjustments need to be made to the Commission's implementation of PURPA, they should be made through the calculation of avoided cost rates and not arbitrarily limiting the term of the contract to a length that is intentionally designed to prohibit financing or otherwise ensure that no QF receives capacity payments.

Q. **DOES THIS END YOUR TESTIMONY AS OF APRIL 23, 2015?**

A. Yes.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NOS. IPC-E-15-01, AVU-E-15-01, PAC-E-15-03

J.R. SIMPLOT COMPANY AND

CLEARWATER PAPER CORPORATION

READING, DI

TESTIMONY

EXHIBIT NO. 201

	Don C. Reading
Present position	Vice President and Consulting Economist
Education	B.S., Economics; Utah State University M.S., Economics; University of Oregon Ph.d., Economics; Utah State University

Honors and awards	Omicron Delta Epsilon, NSF Fellowship
Professional and business history	Ben Johnson Associates, Inc.: 1989 ---- Vice President 1986 ---- Consulting Economist Idaho Public Utilities Commission: 1981-86 Economist/Director of Policy and Administration Teaching: 1980-81 Associate Professor, University of Hawaii-Hilo 1970-80 Associate and Assistant Professor, Idaho State University 1968-70 Assistant Professor, Middle Tennessee State University
Firm experience	Dr. Reading provides expert testimony concerning economic and regulatory issues. He has testified on more than 35 occasions before utility regulatory commissions in Alaska, California, Colorado, the District of Columbia, Hawaii, Idaho, Nevada, North Dakota, North Carolina, Oregon, Texas, Utah, Wyoming, and Washington. Dr. Reading has more than 35 years experience in the field of economics. He has participated in the development of indices reflecting economic trends, GNP growth rates, foreign exchange markets, the money supply, stock market levels, and inflation. He has analyzed such public policy issues as the minimum wage, federal spending and taxation, and import/export balances. Dr. Reading is one of four economists providing yearly forecasts of statewide personal income to the State of Idaho for purposes of establishing state personal income tax rates. In the field of telecommunications, Dr. Reading has provided expert testimony on the issues of marginal cost, price elasticity, and measured service. Dr. Reading prepared a state-specific study of the price elasticity of demand for local telephone service in Idaho and recently conducted research for, and directed the preparation of, a report to the Idaho legislature regarding the status of telecommunications competition in that state.

Dr. Reading's areas of expertise in the field of electric power include demand forecasting, long-range planning, price elasticity, marginal and average cost pricing, production-simulation modeling, and econometric modeling. Among his recent cases was an electric rate design analysis for the Industrial Customers of Idaho Power. Dr. Reading is currently a consultant to the Idaho Legislature=s Committee on Electric Restructuring.

For the past three years Dr. Reading has been a consultant to Idaho Connects On Line (ICON), a virtual charter school, providing data analysis and statistical support. In addition to building a model that replicated the Idaho's Star Rating System he completed a study focused on the demographic and socioeconomic characteristics of the school's population and academic achievements. He is currently working with the measurement of ICON's Mission Specific goals for the 2014-2015 school year.

Since 1999 Dr. Reading has been affiliated with the Climate Impact Group (CIG) at the University of Washington. His work with the CIG has involved an analysis of the impact of Global Warming on the hydo facilities on the Snake River. It also includes an investigation into water markets in the Northwest and Florida. In addition he has analyzed the economics of snowmaking for ski area's impacted by Global Warming.

Among Dr. Reading's recent projects are a FERC hydropower relicensing study (for the Skokomish Indian Tribe) and an analysis of Northern States Power's North Dakota rate design proposals affecting large industrial customers (for J.R. Simplot Company). Dr. Reading has also performed analysis for the Idaho Governor's Office of the impact on the Northwest Power Grid of various plans to increase salmon runs in the Columbia River Basin.

Dr. Reading has prepared econometric forecasts for the Southeast Idaho Council of Governments and the Revenue Projection Committee of the Idaho State Legislature. He has also been a member of several Northwest Power Planning Council Statistical Advisory Committees and was vice chairman of the Governor's Economic Research Council in Idaho

While at Idaho State University, Dr. Reading performed demographic studies using a cohort/survival model and several economic impact studies using input/output analysis. He has also provided expert testimony in cases concerning loss of income resulting from wrongful death, injury, or employment discrimination

Dr. Reading has recently completed a public interest water rights transfer case. He has also just completed an economic impact analysis of the of the proposed Boulder White Clouds National Monument.

Publications	"Energizing Idaho", Idaho Issues Online, Boise State University, Fall 2006. www.boisestate.edu/history/issuesonline/fall2006_issues/index.html The Economic Impact of the 2001 Salmon Season In Idaho, Idaho Fish and Wildlife Foundation, April 2003. The Economic Impact of a Restored Salmon Fishery in Idaho, Idaho Fish and Wildlife Foundation, April, 1999. The Economic Impact of Steelhead Fishing and the Return of Salmon Fishing in Idaho, Idaho Fish and Wildlife Foundation, September, 1997. ACost Savings from Nuclear Resources Reform: An Econometric Model@ (with E. Ray Canterbery and Ben Johnson) *Southern Economic Journal*, Spring 1996. A Visitor Analysis for a Birds of Prey Public Attraction, Peregrine Fund, Inc., November, 1988. Investigation of a Capitalization Rate for Idaho Hydroelectric Projects, Idaho State Tax Commission, June, 1988. "Post-PURPA Views," In Proceedings of the NARUC Biennial Regulatory Conference, 1983. An Input-Output Analysis of the Impact from Proposed Mining in the Challis Area (with R. Davies). Public Policy Research Center, Idaho State University, February 1980. *Phosphate and Southeast: A Socio Economic Analysis* (with J. Eyre, et al). Government Research Institute of Idaho State University and the Southeast Idaho Council of Governments, August 1975. *Estimating General Fund Revenues of the State of Idaho* (with S. Ghazanfar and D. Holley). Center for Business and Economic Research, Boise State University, June 1975. "A Note on the Distribution of Federal Expenditures: An Interstate Comparison, 1933-1939 and 1961-1965." In *The American Economist*, Vol. XVIII, No. 2 (Fall 1974), pp. 125-128. "New Deal Activity and the States, 1933-1939." In *Journal of Economic History*, Vol. XXXIII, December 1973, pp. 792-810.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NOS. IPC-E-15-01, AVU-E-15-01, PAC-E-15-03

J.R. SIMPLOT COMPANY AND

CLEARWATER PAPER CORPORATION

READING, DI

TESTIMONY

EXHIBIT NO. 202

Code of Federal Regulations
Title 18. Conservation of Power and Water Resources
Chapter I. Federal Energy Regulatory Commission, Department of Energy
Subchapter K. Regulations Under the Public Utility Regulatory Policies Act of 1978
Part 292. Regulations Under Sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 with Regard to Small Power Production and Cogeneration. (Refs & Annos)
Subpart C. Arrangements Between Electric Utilities and Qualifying Cogeneration and Small Power Production Facilities Under Section 210 of the Public Utility Regulatory Policies Act of 1978 (Refs & Annos)

18 C.F.R. § 292.304

§ 292.304 Rates for purchases.

Currentness

(a) Rates for purchases.

(1) Rates for purchases shall:

(i) Be just and reasonable to the electric consumer of the electric utility and in the public interest; and

(ii) Not discriminate against qualifying cogeneration and small power production facilities.

(2) Nothing in this subpart requires any electric utility to pay more than the avoided costs for purchases.

(b) Relationship to avoided costs.

(1) For purposes of this paragraph, "new capacity" means any purchase from capacity of a qualifying facility, construction of which was commenced on or after November 9, 1978.

(2) Subject to paragraph (b)(3) of this section, a rate for purchases satisfies the requirements of paragraph (a) of this section if the rate equals the avoided costs determined after consideration of the factors set forth in paragraph (e) of this section

(3) A rate for purchases (other than from new capacity) may be less than the avoided cost if the State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or the nonregulated electric utility determines that a lower rate is consistent with paragraph (a) of this section, and is sufficient to encourage cogeneration and small power production.

(4) Rates for purchases from new capacity shall be in accordance with paragraph (b)(2) of this section, regardless of whether the electric utility making such purchases is simultaneously making sales to the qualifying facility.

(5) In the case in which the rates for purchases are based upon estimates of avoided costs over the specific term of the contract or other legally enforceable obligation, the rates for such purchases do not violate this subpart if the rates for such purchases differ from avoided costs at the time of delivery.

(c) Standard rates for purchases.

(1) There shall be put into effect (with respect to each electric utility) standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less.

(2) There may be put into effect standard rates for purchases from qualifying facilities with a design capacity of more than 100 kilowatts.

(3) The standard rates for purchases under this paragraph:

(i) Shall be consistent with paragraphs (a) and (e) of this section; and

(ii) May differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies.

(d) Purchases "as available" or pursuant to a legally enforceable obligation. Each qualifying facility shall have the option either:

(1) To provide energy as the qualifying facility determines such energy to be available for such purchases, in which case the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery; or

(2) To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either:

(i) The avoided costs calculated at the time of delivery; or

(ii) The avoided costs calculated at the time the obligation is incurred.

(e) Factors affecting rates for purchases. In determining avoided costs, the following factors shall, to the extent practicable, be taken into account:

(1) The data provided pursuant to § 292.302(b), (c), or (d), including State review of any such data;

(2) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:

(i) The ability of the utility to dispatch the qualifying facility;

(ii) The expected or demonstrated reliability of the qualifying facility;

(iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;

(iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;

(v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

(vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and

(vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and

(3) The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2) of this section, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

(4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

(f) Periods during which purchases not required.

(1) Any electric utility which gives notice pursuant to paragraph (f)(2) of this section will not be required to purchase electric energy or capacity during any period during which, due to operational circumstances, purchases from qualifying facilities will result in costs greater than those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself.

(2) Any electric utility seeking to invoke paragraph (f)(1) of this section must notify, in accordance with applicable State law or regulation, each affected qualifying facility in time for the qualifying facility to cease the delivery of energy or capacity to the electric utility.

(3) Any electric utility which fails to comply with the provisions of paragraph (f)(2) of this section will be required to pay the same rate for such purchase of energy or capacity as would be required had the period described in paragraph (f)(1) of this section not occurred.

(4) A claim by an electric utility that such a period has occurred or will occur is subject to such verification by its State regulatory authority as the State regulatory authority determines necessary or appropriate, either before or after the occurrence.

SOURCE: 44 FR 65746, Nov. 15, 1979; 45 FR 12234, Feb. 25, 1980; 50 FR 40358, Oct. 3, 1985; 52 FR 5280, Feb. 20, 1987; 52 FR 28467, July 30, 1987; 53 FR 15381, April 29, 1988; 53 FR 27002, July 18, 1988; 53 FR 40724, Oct. 18, 1988; 57 FR 21734, May 22, 1992; 60 FR 4856, Jan. 25, 1995, unless otherwise noted.

AUTHORITY: 16 U.S.C. 791a–825r, 2601–2645; 31 U.S.C. 9701; 42 U.S.C. 7101–7352.; Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 2601 et seq., Energy Supply and Environmental Coordination Act, 15 U.S.C. 791 et seq. Federal Power Act, 16 U.S.C. 792 et seq., Department of Energy Organization Act, 42 U.S.C. 7101 et seq., E.O. 12009, 42 FR 46267.

Notes of Decisions (120)

Current through April 9, 2015; 80 FR 19036

End of Document

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NOS. IPC-E-15-01, AVU-E-15-01, PAC-E-15-03

J.R. SIMPLOT COMPANY AND

CLEARWATER PAPER CORPORATION

READING, DI

TESTIMONY

EXHIBIT NO. 203

structural failure of the airframe, accomplish a comprehensive inspection of all areas modified by The Raisbeck Group, as follows:

A. Before further flight, inspect for deviations from the supplemental type design in accordance with Paragraphs I through IV, and VI, of FAA approved Raisbeck Service Bulletin No. 25. Inspect for discrepancies such as:

1. Plugged holes
2. Oblong, eggshaped, oversized, or irregular holes
3. Tapered holes
4. Excess holes
5. Inadequate edge distances
6. Gouges
7. Improper fasteners (type and number)
8. Improper clearances
9. Any other irregularities which are not consistent with standard aircraft practice.

B. Before accumulation of 2,000 flight hours time-in-service after modification by STC SA687NW inspect the horizontal stabilizer and elevator in accordance with Paragraphs V(A) and V(B) of FAA approved Raisbeck Service Bulletin No. 25. Repeat this inspection at intervals not exceeding 5,000 flight hours time-in-service thereafter.

C. Before accumulation of 2,000 flight hours time-in-service after modification by STC SA687NW or STC SA847NW, inspect the wing leading edge in accordance with Paragraph V(D) of FAA approved Raisbeck Service Bulletin No. 25. Repeat this inspection at intervals not exceeding 5,000 flight hours time-in-service thereafter.

D. Before accumulation of 10,000 flight hours time-in-service after modification by STC SA687NW or STC SA847NW, inspect the overwing modification in accordance with Paragraph V(C) of FAA approved Raisbeck Service Bulletin No. 25. Repeat this inspection at intervals not exceeding 10,000 flight hours time-in-service thereafter.

E. Inspections are to be conducted at facilities specifically authorized by the Chief, Engineering and Manufacturing Branch, FAA Northwest Region.

F. Discrepancies discovered as a result of the inspections are to be reported to the Chief, Engineering and Manufacturing Branch, FAA Northwest Region. Repair or modifications required because of these problems are to be FAA approved by the Chief, Engineering and Manufacturing Branch, FAA, Northwest Region or specifically authorized DERs.

G. Airplanes may be ferried, in accordance with FAR 21.199, to a maintenance base, for the purpose of complying with this AD.

H. The inspections noted herein may be accomplished as noted or in a manner approved by the Chief, Engineering and Manufacturing Branch, FAA, Northwest Region.

I. Areas previously inspected in accordance with Amendment 39-3680 may be excluded from the inspections required by this AD.

The manufacturer's specifications and procedures identified and described in this directive are incorporated herein and made a part hereof pursuant to 5 U.S.C. 552(a)(1).

All persons affected by this directive who have not already received these documents from the manufacturer, may obtain copies upon request to The Raisbeck Group, 7777 Perimeter Road, Seattle, Washington 98108.

This amendment becomes effective upon publication in the Federal Register and was effective earlier to all recipients of the telegraphic AD T80-NW-2 dated January 17, 1980.

(Secs. 313(1), 601, and 603, Federal Aviation Act of 1958, as amended (49 U.S.C. 1354(a), 1421, and 1423) and Section 6(c) of the Department of Transportation Act (49 U.S.C. 1655(c)); and 14 CFR 11.89)

Note.—The FAA has determined that this document involves a regulation which is not considered to be significant under the provisions of Executive Order 12044 and as implemented by Department of Transportation Regulatory Policies and Procedures (44 FR 11034; February 26, 1979).

Issued in Seattle, Washington, on February 13, 1980.

Note.—The incorporation by reference provisions in the document were approved by the Director of the Federal Register on June 19, 1967.

C. B. Walk, Jr.,
Director, Northwest Region.

[FR Doc. 80-5638 Filed 2-22-80; 8:45 am]
BILLING CODE 4910-13-M

OFFICE OF THE UNITED STATES TRADE REPRESENTATIVE

15 CFR Chapter XX

CFR Chapter Heading and Nomenclature Change

February 19, 1980.

AGENCY: Office of the United States Trade Representative.

ACTION: Final rule.

SUMMARY: This rule changes Chapter XX of Title 15, Code of Federal Regulations, from "Office of the Special Representative for Trade Negotiations" to "Office of the United States Trade Representative." Within the body of the Chapter XX, all references to the "Office of the Special Representative for Trade Negotiations", to the "Special Representative for Trade Negotiations", and to the "Special Representative" or "Deputy Special Representative" are changed to the "Office of the United States Trade Representative", to "the United States Trade Representative", and the "Trade Representative" or "Deputy Trade Representative" respectively. These changes are authorized as part of Reorganization Plan No. 3 of 1979 (44 FR 69273) which was implemented by Executive Order No. 12188 of January 2, 1980 (45 FR 989).

EFFECTIVE DATE: February 25, 1980.

FOR FURTHER INFORMATION CONTACT: Alice Zalik, General Council's Office, Office of the United States Trade Representative, 1800 G Street, NW., Washington, D.C. 20506. (202) 395-3432.

Accordingly, each reference to "the Office of the Special Representative for Trade Negotiations" contained within Chapter XX of Title 15 of the Code of Federal Regulations, including the heading, is changed to "the Office of the United States Trade Representative". Each reference to "the Special Representative for Trade Negotiations" contained within the chapter is changed to "the United States Trade Representative". Each reference to the "Special Representative" and to the "Deputy Special Representative" is changed to the "Trade Representative" and to the "Deputy Trade Representative" respectively.

Robert C. Cassidy,
General Counsel.

[FR Doc. 80-5605 Filed 2-22-80; 8:45 am]
BILLING CODE 3190-01-M

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 292

[Docket No. RM79-55, Order No. 69]

Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission hereby adopts regulations that implement section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA). The rules require electric utilities to purchase electric power from and sell electric power to qualifying cogeneration and small power production facilities, and provide for the exemption of qualifying facilities from certain federal and State regulation. Implementation of these rules is reserved to State regulatory authorities and nonregulated electric utilities.

EFFECTIVE DATE: March 20, 1980.

FOR FURTHER INFORMATION CONTACT:
Ross Ain, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, 202-357-8446.
John O'Sullivan, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, 202-357-8477.
Adam Wenner, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, 202-357-8033.

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Many commenters at the Commission's public hearings and in written comments recommended that the Commission should require the establishment of "net energy billing" for small qualifying facilities. Under this billing method, the output from a qualifying facility reverses the electric meter used to measure sales from the electric utility to the qualifying facility. The Commission believes that this billing method may be an appropriate way of approximating avoided cost in some circumstances, but does not believe that this is the only practical or appropriate method to establish rates for small qualifying facilities. The Commission observes that net energy billing is likely to be appropriate when the retail rates are marginal cost-based, time-of-day rates. Accordingly, the Commission will leave to the State regulatory authorities and the nonregulated electric utilities the determination as to whether to institute net energy billing.

Paragraph (c)(3)(i) provides that standard rates for purchase should take into account the factors set forth in paragraph (e). These factors relate to the quality of power from the qualifying facility, and its ability to fit into the purchasing utility's generating mix.

Paragraph (e)(vi) is of particular significance for facilities of 100 kW or less. This paragraph provides that rates for purchase shall take into account "the individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system . . .". Several commenters presented persuasive evidence showing that an effective amount of capacity may be provided by dispersed small systems, even in the case where delivery of energy from any particular facility is stochastic. Similarly, qualifying facilities may be able to enter into operating agreements with each other by which they are able to increase the assured availability of capacity to the utility by coordinating scheduled maintenance and providing mutual back-up service. To the extent that this aggregate capacity value can be reasonably estimated, it must be reflected in standard rates for purchases.

Several commenters observed that the patterns of availability of particular energy sources can and should be reflected in standard rates. An example of this phenomenon is the availability of wind and photovoltaic energy on a summer peaking system. If it can be shown that system peak occurs when there is bright sun and no wind, rates for purchase could provide a higher capacity payment for photovoltaic cells than for wind energy conversion systems. For systems peaking on dark windy days, the reverse might be true. Subparagraph (3)(ii) thus provides that standard rates for purchases may differentiate among qualifying facilities on the basis of the supply characteristics of the particular technology.

§§ *292.304 (b)(5) and (d) Legally enforceable obligations.*

Paragraphs (b)(5) and (d) are intended to reconcile the requirement that the rates for purchases equal the utilities' avoided cost with the need for qualifying facilities to be able to enter into contractual commitments based, by necessity, on estimates of future avoided costs. Some of the comments received regarding this section stated that, if the avoided cost of energy at the time it is supplied is less than the price provided in the contract or obligation, the purchasing utility would be required to pay a rate for purchases that would subsidize the qualifying facility at the expense of the utility's other ratepayers. The Commission recognizes this possibility, but is cognizant that in other cases, the required rate will turn out to be lower than the avoided cost at the time of purchase. The Commission does not believe that the reference in the statute to the incremental cost of alternative energy was intended to require a minute-by-minute evaluation of costs which would be checked against rates established in long term contracts between qualifying facilities and electric utilities.

Many commenters have stressed the need for certainty with regard to return on investment in new technologies. The Commission agrees with these latter arguments, and believes that, in the long run, "overestimations" and "underestimations" of avoided costs will balance out.

Paragraph (b)(5) addresses the situation in which a qualifying facility has entered into a contract with an electric utility, or where the qualifying facility has agreed to obligate itself to deliver at a future date energy and capacity to the electric utility. The import of this section is to ensure that a qualifying facility which has obtained the certainty of an arrangement is not deprived of the benefits of its commitment as a result of changed circumstances. This provision can also work to preserve the bargain entered into by the electric utility; should the actual avoided cost be higher than those contracted for, the electric utility is nevertheless entitled to retain the benefit of its contracted for, or otherwise legally enforceable, lower price for purchases from the qualifying facility. This subparagraph will thus ensure the certainty of rates for purchases from a qualifying facility which enters into a commitment to deliver energy or capacity to a utility.

Paragraph (d)(1) provides that a qualifying facility may provide energy or capacity on an "as available" basis, i.e., without legal obligation. The proposed rule provided that rates for such purchases should be based on "actual" avoided costs. Many comments noted that basing rates for purchases in such cases on the utility's "actual avoided costs" is misleading and could require retroactive ratemaking. In light of these comments, the Commission has revised the rule to provide that the rates for purchases are to be based on the purchasing utility's avoided costs estimated at the time of delivery.[14]

Paragraph (d)(2) permits a qualifying facility to enter into a contract or other legally enforceable obligation to provide energy or capacity over a specified term. Use of the term "legally enforceable obligation" is intended to prevent a utility from circumventing the requirement that provides capacity credit for an eligible qualifying facility merely by refusing to enter into a contract with the qualifying facility.

Many commenters noted the same problems for establishing rates for purchases under subparagraph (2) as in subparagraph (1). The Commission intends that rates for purchases be based, at the option of the qualifying facility, on either the avoided costs at the time of delivery or the avoided costs calculated at the time the obligation is incurred. This change enables a qualifying facility to establish a fixed contract price for its energy and capacity at the outset of its obligation or to receive the avoided costs determined at the time of delivery.

A facility which enters into a long term contract to provide energy or capacity to a utility may wish to receive a greater percentage of the total purchase price during the beginning of the obligation. For example, a level payment schedule from the utility to the qualifying facility may be used to match more closely the schedule of debt service of the facility. So long as the total payment over the duration of the contract term does not exceed the estimated avoided costs, nothing in these rules would prohibit a State regulatory authority or non-regulated electric utility from approving such an arrangement.

[14] In addition to the avoided costs of energy, these costs must include the prorated share of the aggregate capacity value of such facilities.

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§ 292.304(c) Factors affecting rates for purchases.

Capacity Value

An issue basic to this paragraph is the question of recognition of the capacity value of qualifying facilities.

In the proposed rule, the Commission adopted the argument set forth in the Staff Discussion Paper that the proper interpretation of section 210(b) of PURPA requires that the rates for purchases include recognition of the capacity value provided by qualifying cogeneration and small power production facilities. The Commission noted that language used in section 210 of PURPA and the Conference Report as well as in the Federal Power Act supports this proposition.

In the proposed rule, the Commission cited the final paragraph of the Conference Report with regard to section 210 of PURPA:

> The conferees expect that the Commission, in judging whether the electric power supplied by the cogenerator or small power producer will replace future power which the utility would otherwise have to generate itself either through existing capacity or additions to capacity or purchase from other sources, will take into account the reliability of the power supplied by the cogenerator or small power producer by reason of any legally enforceable obligation of such cogenerator or small power producer to supply firm power to the utility.[15]

In addition to that citation, the Commission notes that the Conference Report states that:

> In interpreting the term "incremental costs of alternative energy", the conferees expect that the Commission and the States may look beyond the costs of alternative sources which are instantaneously available to the utility.[16]

Several commenters contended that, since section 210(a)(2) of PURPA provides that electric utilities must "purchase electric energy" from qualifying facilities, the rate for such purchases should not include payments for capacity. The Commission observes that the statutory language used in the Federal Power Act uses the term "electric energy" to describe the rates for sales for resale in interstate commerce. Demand or capacity payments are a traditional part of such rates. The term "electric energy" is used throughout the Act to refer both to electric energy and capacity. The Commission does not find any evidence that the term "electric energy" in section 210 of PURPA was intended to refer only to fuel and operating and maintenance expenses, instead of all of the costs associated with the provision of electric service.

In addition, the Commission notes that to interpret this phrase to include only energy would lead to the conclusion that the rates for sales *to* qualifying facilities could only include the energy component of the rate since section 210 also refers to "electric energy" with regard to such sales. It is the Commission's belief that this was not the intended result. This provides an additional reason to interpret the phrase "electric energy" to include both energy and capacity.

In implementing this statutory standard, it is helpful to review industry practice respecting sales between utilities. Sales of electric power are ordinarily classified as either firm sales, where the seller provides power at the customer's request, or non-firm power sales, where the seller and not the buyer makes the decision whether or not power is to be available. Rates for firm power purchases include payments for the cost of fuel and operating expenses, and also for the fixed costs associated with the construction of generating units needed to provide power at the purchaser's discretion. The degree of certainty of deliverability required to constitute "firm power" can ordinarily be obtained only if a utility has several generating units and adequate reserve capacity. The capacity payment, or demand charge, will reflect the cost of the utility's generating units.

In contrast, the ability to provide electric power at the selling utility's discretion imposes no requirement that the seller construct or reserve capacity. In order to provide power to customers at the seller's discretion, the selling utility need only charge for the cost of operating its generating units and administration. These costs, called "energy" costs, ordinarily are the ones associated with non-firm sales of power.

Purchases of power from qualifying facilities will fall somewhere on the continuum between these two types of electric service. Thus, for example, wind machines that furnish power only when wind velocity exceeds twelve miles per hour may be so uncertain in availability of output that they would only permit a utility to avoid generating an equivalent amount of energy. In that situation, the utility must continue to provide capacity that is available to meet the needs of its customers. Since there are no avoided capacity costs, rates for such sporadic purchases should thus be based on the utility system's avoided incremental cost of energy. On the other hand, testimony at the Commission's public hearings indicated that effective amounts of firm capacity exist for dispersed wind systems, even though each machine, considered separately, could not provide capacity value. The aggregate capacity value of such facilities must be considered in the calculation of rates for purchases, and the payment distributed to the class providing the capacity.

Some technologies, such as photovoltaic cells, although subject to some uncertainty in power output, have the general advantage of providing their maximum power coincident with the system peak when used on a summer peaking system. The value of such power is greater to the utility than power delivered during off-peak periods. Since the need for capacity is based, in part, on system peaks, the qualifying facility's coincidence with the system peak should be reflected in the allowance of some capacity value and an energy component that reflects the avoided energy costs at the time of the peak.

A facility burning municipal waste or biomass may be able to operate more predictably and reliably than solar or wind systems. It can schedule its outages during times when demand on the utility's system is low. If such a unit demonstrates a degree of reliability that would permit the utility to defer or avoid construction of a generating unit or the purchase of firm power from another utility, then the rate for such a purchase should be based on the avoidance of both energy and capacity costs.

In order to defer or cancel the construction of new generating units, a utility must obtain a commitment from a qualifying facility that provides contractual or other legally enforceable assurances that capacity from alternative sources will be available sufficiently ahead of the date on which the utility would otherwise have to commit itself to the construction or purchase of new capacity. If a qualifying facility provides such assurances, it is entitled to receive rates based on the capacity costs that the utility can avoid as a result of its obtaining capacity from the qualifying facility.

Other comments with regard to the requirement to include capacity payments in avoided costs generally track those set forth in the Staff Discussion Paper and the proposed rule. The thrust of these comments is that, in order to receive credit for capacity and to comply with the requirement that rates for purchases not exceed the incremental cost of alternative energy, capacity payments can only be required when the availability of capacity from a qualifying facility or facilities actually permits the purchasing utility to reduce

[15] Conference Report on H.R. 4018, Public Utility Regulatory Policies Act of 1978, H. Rep. No. 1750, 99, 95th Cong., 2d Sess. (1978).

[16] *Id.*, pp. 98-9.

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its need to provide capacity by deferring the construction of new plant or commitments to firm power purchase contracts. In the proposed rule, the Commission stated that if a qualifying facility offers energy of sufficient reliability and with sufficient legally enforceable guarantees of deliverability to permit the purchasing electric utility to avoid the need to construct a generating plant, to enable it to build a smaller, less expensive plant, or to purchase less firm power from another utility than it would otherwise have purchased, then the rates for purchases from the qualifying facility must include the avoided capacity and energy costs. As indicated by the preceding discussion, the Commission continues to believe that these principles are valid and appropriate, and that they properly fulfill the mandate of the statute.

The Commission also continues to believe, as stated in the proposed rule, that this rulemaking represents an effort to evolve concepts in a newly developing area within certain statutory constraints. The Commission recognizes that the translation of the principle of avoided capacity costs from theory into practice is an extremely difficult exercise, and is one which, by definition, is based on estimation and forecasting of future occurrences. Accordingly, the Commission supports the recommendation made in the Staff Discussion Paper that it should leave to the States and nonregulated utilities "flexibility for experimentation and accommodation of special circumstances" with regard to implementation of rates for purchases. Therefore, to the extent that a method of calculating the value of capacity from qualifying facilities reasonably accounts for the utility's avoided costs, and does not fail to provide the required encouragement of cogeneration and small power production, it will be considered as satisfactorily implementing the Commission's rules.

§ 292.304(e) Factors affecting rates for purchases.

As noted previously, several commenters observed that the utility system cost data required under § 292.302 cannot be directly applied to rates for purchase. The Commission acknowledges this point and, as discussed previously, has provided that these data are to be used as a starting point for the calculation of an appropriate rate for purchases equal to the utility's avoided cost. Accordingly, the Commission has removed the reference to the utility system cost data from the definition of rates for purchases, and has inserted the reference to these data in paragraph (e), as one factor to be considered in calculating rates for purchases. Subparagraph (1) states that these data shall, to the extent practicable, be taken into account in the calculation of a rate for purchases.

Subparagraph (2) deals with the availability of capacity from a qualifying facility during system daily and seasonal peak periods. If a qualifying facility can provide energy to a utility during peak periods when the electric utility is running its most expensive generating units, this energy has a higher value to the utility than energy supplied during off-peak periods, during which only units with lower running costs are operating.

The preamble to the proposed rule provided that, to the extent that metering equipment is available, the State regulatory authority or nonregulated electric utility should take into account the time or season in which the purchase from the qualifying facility occurs. Several commenters interpreted this statement as implying that, by refusing to install metering equipment, an electric utility could avoid the obligation to consider the time at which purchases occur. This is not the intent of this provision. Clearly, the more precisely the time of purchase is recorded the more exact the calculation of the avoided costs, and thus the rate for purchases, can be. Rather than specifying that exact time-of-day or seasonal rates for purchases are required, however, the Commission believes that the selection of a methodology is best left to the State regulatory authorities and nonregulated electric utilities charged with the implementation of these provisions.

Clauses (i) through (v) concern various aspects of the reliability of a qualifying facility. When an electric utility provides power from its own generating units or from those of another electric utility, it normally controls the production of such power from a central location. The ability to so control power production enhances a utility's ability to respond to changes in demand, and thereby enhances the value of that power to the utility. A qualifying facility may be able to enter into an arrangement with the utility which gives the utility the advantage of dispatching the facility. By so doing, it increases its value to the utility. Conversely, if a utility cannot dispatch a qualifying facility, that facility may be of less value to the utility.

Clause (ii) refers to the expected or demonstrated reliability of a qualifying facility. A utility cannot avoid the construction or purchase of capacity if it is likely that the qualifying facility which would claim to replace such capacity may go out of service during the period when the utility needs its power to meet system demand. Based on the estimated or demonstrated reliability of a qualifying facility, the rate for purchases from a qualifying facility should be adjusted to reflect its value to the utility.

Clause (iii) refers to the length of time during which the qualifying facility has contractually or otherwise guaranteed that it will supply energy or capacity to the electric utility. A utility-owned generating unit normally will supply power for the life of the plant, or until it is replaced by more efficient capacity. In contrast, a cogeneration or small power production unit might cease to produce power as a result of changes in the industry or in the industrial processes utilized. Accordingly, the value of the service from the qualifying facility to the electric utility may be affected by the degree to which the qualifying facility ensures by contract or other legally enforceable obligation that it will continue to provide power. Included in this determination, among other factors, are the term of the commitment, the requirement for notice prior to termination of the commitment, and any penalty provisions for breach of the obligation.

In order to provide capacity value to an electric utility a qualifying facility need not necessarily agree to provide power for the life of the plant. A utility's generation expansion plans often include purchases of firm power from other utilities in years immediately preceding the addition of a major generation unit. If a qualifying facility contracts to deliver power, for example, for a one year period, it may enable the purchasing utility to avoid entering into a bulk power purchase arrangement with another utility. The rate for such a purchase should thus be based on the price at which such power is purchased, or can be expected to be purchased, based upon bona fide offers from another utility.

Clause (iv) addresses periods during which a qualifying facility is unable to provide power. Electric utilities schedule maintenance outages for their own generating units during periods when demand is low. If a qualifying facility can similarly schedule its maintenance outages during periods of low demand, or during periods in which a utility's own capacity will be adequate to handle existing demand, it will enable the utility to avoid the expenses associated with providing an equivalent amount of

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capacity. These savings should be reflected in the rate for purchases.

Clause (v) refers to a qualifying facility's ability and willingness to provide capacity and energy during system emergencies. Section 292.307 of these regulations concerns the provision of electric service during system emergencies. It provides that, to the extent that a qualifying facility is willing to forego its own use of energy during system emergencies and provide power to a utility's system, the rate for purchases from the qualifying facility should reflect the value of that service. Small power production and cogeneration facilities could provide significant back-up capability to electric systems during emergencies. One benefit of the encouragement of interconnected cogeneration and small power production may be to increase overall system reliability during such emergency conditions. Any such benefit should be reflected in the rate for purchases from such qualifying facilities.

Another related factor which affects the capacity value of a qualifying facility is its ability to separate its load from its generation during system emergencies. During such emergencies an electric utility may institute load shedding procedures which may, among other things, require that industrial customers or other large loads stop receiving power. As a result, to provide optimal benefit to a utility in an emergency situation, a qualifying facility might be required to continue operation as a generating plant, while simultaneously ceasing operation as a load on the utility's system. To the extent that a facility is unable to separate its load from its generation, its value to the purchasing utility decreases during system emergencies. To reflect such a possibility, clause (v) provides that the purchasing utility may consider the qualifying facility's ability to separate its load from its generation during system emergencies in determining the value of the qualifying facility to the electric utility.

Clause (vi) refers to the aggregate capability of capacity from qualifying facilities to displace planned utility capacity. In some instances, the small amounts of capacity provided from qualifying facilities taken individually might not enable a purchasing utility to defer or avoid scheduled capacity additions. The aggregate capability of such purchases may, however, be sufficient to permit the deferral or avoidance of a capacity addition. Moreover, while an individual qualifying facility may not provide the equivalent of firm power to the electric utility, the diversity of these facilities may collectively comprise the equivalent of capacity.

Clause (vii) refers to the fact that the lead time associated with the addition of capacity from qualifying facilities may be less than the lead time that would have been required if the purchasing utility had constructed its own generating unit. Such reduced lead time might produce savings in the utility's total power production costs, by permitting utilities to avoid the "lumpiness," and temporary excess capacity associated therewith, which normally occur when utilities bring on line large generating units. In addition, reduced lead time provides the utility with greater flexibility with which it can accommodate changes in forecasts of peak demand.

Subparagraph (3) concerns the relationship of energy or capacity from a qualifying facility to the purchasing electric utility's need for such energy or capacity. If an electric utility has sufficient capacity to meet its demand, and is not planning to add any new capacity to its system, then the availability of capacity from qualifying facilities will not immediately enable the utility to avoid any capacity costs. However, an electric utility system with excess capacity may nevertheless plan to add new, more efficient capacity to its system. If purchases from qualifying facilities enable a utility to defer or avoid these new planned capacity additions, the rate for such purchases should reflect the avoided costs of these additions. However, as noted by several commenters, the deferral or avoidance of such a unit will also prevent the substitution of the lower energy costs that would have accompanied the new capacity. As a result, the price for the purchase of energy and capacity should reflect these lower avoided energy costs that the utility would have incurred had the new capacity been added.

This is not to say that electric utilities which have excess capacity need not make purchases from qualifying facilities; qualifying facilities may obtain payment based on the avoided energy costs on a purchasing utility's system. Many utility systems with excess capacity have intermediate or peaking units which use high-cost fossil fuel. As a result, during peak hours, the energy costs on the systems are high, and thus the rate to a qualifying utility from which the electric utility purchases energy should similarly be high.

Subparagraph (4) addresses the costs or savings resulting from line losses. An appropriate rate for purchases from a qualifying facility should reflect the cost savings actually accruing to the electric utility. If energy produced from a qualifying facility undergoes line losses such that the delivered power is not equivalent to the power that would have been delivered from the source of power it replaces, then the qualifying facility should not be reimbursed for the difference in losses. If the load served by the qualifying facility is closer to the qualifying facility than it is to the utility, it is possible that there may be net savings resulting from reduced line losses. In such cases, the rates should be adjusted upwards.

§ 292.303(f) Periods during which purchase are not required.

The proposed rule provided that an electric utility will not be required to purchase energy and capacity from qualifying facilities during periods in which such purchases will result in net increased operating costs to the electric utility. This section was intended to deal with a certain condition which can occur during light loading periods. If a utility operating only base load units during these periods were forced to cut back output from the units in order to accommodate purchases from qualifying facilities, these base load units might not be able to increase their output level rapidly when the system demand later increased. As a result, the utility would be required to utilize less efficient, higher cost units with faster start-up to meet the demand that would have been supplied by the less expensive base load unit had it been permitted to operate at a constant output.

The result of such a transaction would be that rather than avoiding costs as a result of the purchase from a qualifying facility, the purchasing electric utility would incur greater costs than it would have had it not purchased energy or capacity from the qualifying facility. A strict application of the avoided cost principle set forth in this section would assess these additional costs as negative avoided costs which must be reimbursed by the qualifying facility. In order to avoid the anomalous result of forcing a qualifying utility to pay an electric utility for purchasing its output, the Commission proposed that an electric utility be required to identify periods during which this situation would occur, so that the qualifying facility could cease delivery of electricity during those periods.

Many of the comments received reflected a suspicion that electric utilities would abuse this paragraph to circumvent their obligation to purchase from qualifying facilities. In order to minimize that possibility, the Commission has revised this paragraph

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NOS. IPC-E-15-01, AVU-E-15-01, PAC-E-15-03

J.R. SIMPLOT COMPANY AND

CLEARWATER PAPER CORPORATION

READING, DI

TESTIMONY

EXHIBIT NO. 204

Exhibit No.___(GND-7CT)
Docket UE-130043
Witness: Gregory N. Duvall

**BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION**

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFICORP d/b/a Pacific Power & Light Company Respondent.	Docket UE-130043

PACIFICORP

REDACTED REBUTTAL TESTIMONY OF GREGORY N. DUVALL

August 2, 2013

should consider changes in this case as a part of the post-trial period review of the WCA.[16]

Q. Did parties accept any of the Company's proposed modifications to the WCA?

A. Yes. Staff explicitly supported the Company's proposal to include the entire Idaho Power PTP transmission contract in the WCA, apparently on the basis that it reduces NPC.[17] While Boise challenged a list of what it characterized as the proposed changes to the WCA and argued generally that changes to the WCA were not reasonable at this juncture, it chose not to remove the change to the Idaho Power PTP contract.[18]

California and Oregon QF contracts

Q. Does any party support the Company's proposal to include the costs associated with Oregon and California QF contracts in west control area NPC?

A. No. Staff, Boise, and Public Counsel each argue against inclusion of California and Oregon QF contracts in west control area NPC.[19] In one form or another, the parties all assert that allocating west control area QF contracts to Washington inappropriately requires Washington customers to pay for QF-related policy choices made by Oregon and California.

Q. Are all of the contested QF contracts from renewable resources?

A. Yes. The QF contracts are all connected to renewable resources located in Oregon and California. Because the QF contracts do not include renewable energy credits

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[16] *Id.*, ¶ 159.
[17] Exhibit No.___(DCG-1CT) at page 7.
[18] Exhibit No.___(MCD-1CT) at pages 5-6.
[19] *See* Exhibit No.___(MCD-1CT) at pages 5-8; Exhibit No.___(DCG-1CT) at pages 8-13; Exhibit No.___(SC-1CT) at pages 15-18.

(RECs), however, the Company may not use them to comply with the EIA.[20]

Q. Is one of the goals of PURPA to support the development of renewable energy resources?

A. Yes. FERC has observed that: "With PURPA, Congress was seeking to diversify the Nation's generation mix and promote more efficient use of fossil fuels when they were used for generation by encouraging renewable technologies and cogeneration, in order to cushion against further price shock and reduce dependence on fossil fuels."[21]

Q. Does Washington state policy promote the development and use of renewable energy?

A. Yes. There are strong statements in support of renewable energy development and use in the declaration of policies included in the EIA and in the legislative findings that support the EPS.[22]

Q. Did the Commission recently adopt policies to promote the development of small renewable generation?

A. Yes. On July 19, 2013, the Commission adopted new rules to simplify the process to connect small energy systems, which are often solar or wind generators, to the electrical system. In announcing the new rules, Commission Chairman David Danner said: "By streamlining these rules we are advancing Washington's policies that encourage renewable energy, including distributed generation. This is one more step

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[20] RCW 19.285 *et seq.*
[21] *In re Southern California Edison*, 71 F.E.R.C. P 61,269, 62,079 (1995).
[22] RCW 189.285.020; RCW 70.235.005; and RCW 80.80.005(1)(d).

to help Washington's citizens and businesses participate in our state's efforts to reduce greenhouse gas emissions."[23]

Q. Is asking Washington customers to pay their allocated share of the Company's west control area QF contracts (while other west control area states also pay their allocated share of Washington's QF contracts) contrary to Washington state energy policy?

A. No. Washington, like its neighbors in Oregon and California, clearly supports the underlying policy goals of PURPA. Indeed, continuing to single out QF contracts for different regulatory treatment than any other west control area resource discriminates against small, renewable resources in a manner that appears directly contrary to Washington energy policy.

Q. Has the number of Oregon and California QF contracts included in the Company's case decreased since its initial filing?

A. Yes. Since the initial filing, four Oregon QF contracts were terminated. The impact of removing these contracts is included in the Company's rebuttal NPC. This update also reduces the impact of parties' proposed adjustments to exclude Oregon and California QF contracts by approximately 10 percent.

Q. Does PURPA include specific provisions related to utility cost recovery for QF contracts?

A. Yes. I understand that PURPA specifically requires that electric utilities "recover[] all prudently incurred costs associated with the purchase" of energy or capacity from

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[23] http://www.utc.wa.gov/aboutUs/Lists/News/DispForm.aspx?ID=209

a QF contract.[24] The Company's proposal in this case modifies the WCA to provide for the full cost recovery for QF contracts dictated by PURPA.

Q. What specific justification does Staff provide for the exclusion of the Company's contracts with QFs in Oregon and California?

A. Staff first argues that inter-jurisdictional allocation is not based on actual power flow studies and therefore the fact that Oregon and California QFs may physically deliver power to meet Washington load is irrelevant.[25] Public Counsel makes the exact opposite argument.[26] It claims that PacifiCorp has failed to provide any analysis showing how Washington load is satisfied by QFs from outside the state and, without such a detailed power flow study, it is not possible to assign these costs to Washington customers. In other words, Staff claims that allocation is not, and has never been, based on power flow studies, and Public Counsel claims that power flow studies are a necessary predicate to any inter-jurisdictional allocation methodology.

Q. How do you respond to these arguments?

A. The Commission has made clear that the Company does not need to "demonstrate each resource in the system provides a direct benefit, i.e., electron flow, to be considered used and useful for service in this state."[27] Public Counsel's claim that a detailed power flow study is necessary is incorrect. However, Staff is also incorrect that the physical location of the Oregon and California QFs within the west control area is irrelevant to their inclusion in west control area NPC.

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[24] 16 U.S.C. § 824a-3(m)(7).
[25] Exhibit No.___(DCG-1CT) at page 10.
[26] Exhibit No.___(SC-1CT) at page 17.
[27] *Wash. Utils. & Transp. Comm'n v. PacifiCorp d/b/a/ Pacific Power & Light Company*, Docket UE-050684, Order 04, ¶ 68 (April 17, 2006).

Q. Please explain.

A. The underlying premise of the WCA is that all generation resources located in the west control area are used and useful to Washington customers and are therefore included in Washington rates. When approving the WCA, the Commission observed: "Based as it is on the generation resources that are actually used to keep the west control area in balance with its neighboring control areas, the WCA method is a solid foundation for determining the resources that actually serve load in Washington.[28] The fact that the Oregon and California QFs are located in the west control area means that, like all other west control area generation resources (including PPAs with non-QF generators), the costs and benefits of these contracts should be included in Washington rates.

Q. Does Staff provide any other justification for the exclusion of costs associated with Oregon and California QF contracts from west control area NPC?

A. Yes. Staff claims that the requirements, size of eligible resources, contract term lengths, and pricing for QF contracts are determined *entirely* by state-specific policies.[29] As discussed above, Staff argues that Washington customers should not be subject to the policy decisions of other states related to QF contracts.

Q. Do other parties make similar arguments?

A. Yes. Boise also argues that Washington customers should be protected from other states' policies on QF contracts.[30]

[28] *Wash. Utils. & Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light Company*, Docket UE-061546, Order 08, ¶ 53 (June 21, 2007).
[29] Exhibit No.___(DCG-1CT) at page 10.
[30] Exhibit No.___(MCD-1CT) at page 7.

Q. Is Staff correct that the requirements, size of eligible resources, contract term lengths, and pricing for QF contracts are driven entirely by state-specific policies?

A. No. I understand that PURPA—a federal statute—requires the Company to enter into QF contracts and makes clear the price paid to a QF cannot exceed the utility's avoided costs.[31] I also understand that FERC regulations govern the specific requirements regarding the types of resources that are eligible for a QF contract,[32] the size of resources eligible for QF contracts,[33] and the methodology for determining avoided cost prices for purposes of QF contracting.[34]

Q. Staff claims that Commission policy dictates shorter contract lengths and smaller capacity sizes than Oregon and California to better protect customers.[35] Do you agree?

A. No. Staff's testimony states that the Commission has established policies that strictly limit QF eligibility for standard contracts and strictly limits standard contract length.[36] However, Staff's claims are at odds with the Commission's rules and Commission-approved PURPA tariffs.

First, Staff states that WAC 480-107-095 limits eligibility for standard contracts to QFs that have a capacity of 2 megawatts (MW) or less.[37] WAC 480-107-095 does not include a cap, however, stating only that "utilities must file a standard

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[31] *See, e.g.*, 16 U.S.C. §§ 824a-3(b), (d); 18 C.F.R. § 292.304(2); *American Paper Institute, Inc. v. American Elec. Power Service Corp.*, 461 U.S. 402, 413 (1983).
[32] *See, e.g.,* 18 C.F.R. §§ 292.203-.205.
[33] *See, e.g.,* 18 C.F.R. § 292.304(c).
[34] *See, e.g.,* 18 C.F.R. § 292.304.
[35] Exhibit No.___(DCG-1CT) at page 13.
[36] *Id.* at n. 29.
[37] *Id.*

tariff for purchases from qualifying facilities rated at one megawatt or less." Currently, both PSE's Schedule 91 and Avista's Schedule 62 provide standard offer contracts for QFs with capacities up to 5 MW; PacifiCorp's Schedule 37 provides standard contracts for QFs with capacities up to 2 MW.

Second, Staff states that WAC 480-107-095 provides for fixed pricing for a term of only five years.[38] Again, that rule says nothing about fixed prices or the length of a contract. WAC 480-107-095 merely states that prices may "not exceed the utility's avoided costs for such electric energy, electric capacity, or both," and that the tariff "may be based upon market prices and include incremental costs associated with purchasing small quantities of power."

PacifiCorp's current Schedule 37 publishes a 10-year stream of fixed prices available for a contract term of five years. PSE's tariff specifies that to receive fixed prices, contracts must be *at least* five years in length, and the tariff reflects 15 years of fixed prices. Of note, current Washington prices, which were set in PacifiCorp's 2011 general rate case, Docket UE-111190, include the end of a 25-year QF contract with the City of Walla Walla with calendar year 2014 prices of $156.90 per MWh.

Q. Staff argues that the longer terms of QF contracts in Oregon and California expose customers to increased risks from decreasing avoided cost rates in recent years.[39] How do you respond?

A. Staff overstates this risk by understating the number of Oregon and California contracts entered in the last five years. Staff claims that approximately 34 percent of the QF contracts are post-2009; in fact, of the expected QF generation in 2014

[38] *Id.*
[39] Exhibit No.___(DCG-1CT) at pages 12-13.

included in this case, over 76 percent is from contracts entered in the last five years.[40] The vast majority of the contracts that are included in NPC in this case have been in place five years or less.

Q. Does Boise identify any specific state policies from Oregon and California that it claims are in conflict with Washington policies?

A. Yes. Boise claims that Oregon and California have fixed price standard offer contracts for QFs, but Washington does not.[41] Boise claims that Washington customers should not be exposed to the risk associated with these types of policy decisions made in other states.

Q. Does this argument have merit?

A. No. Boise's argument is premised on an incorrect understanding of Washington's implementation of PURPA. As described earlier, the Company's Schedule 37 tariff in Washington provides a fixed price standard offer option for QFs up to 2 MW of capacity.

Q. Other than the incorrect reference to the lack of a fixed price contract in Washington, does Boise provide any other examples of QF policies in Oregon or California that differ from those in Washington?

A. No. Boise's claims that Washington customers are exposed to harm caused by decisions made by the states of Oregon and California are unsubstantiated.

Q. Are Washington customers harmed by other states' determination of QF prices?

A. No. As I described in my direct testimony, prices paid to QFs are determined based

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[40] This includes the impact of removing the terminated Butter Creek wind QFs. Before removing the Butter Creek QFs, 74 percent of the Company's expected QF generation in the Company's initial filing was from contracts entered in the last five years.

[41] Exhibit No.___(MCD-1CT) at page 6.

on a utility's avoided cost of energy and capacity, in compliance with PURPA. Each state has an approved method for calculating these avoided costs, and the resulting prices are heavily scrutinized and ultimately approved by the respective commissions. The avoided cost calculation is designed to set QF contract prices at a level where customers are indifferent between a utility purchasing from the QF or obtaining energy and capacity from the next available resource. No party has provided evidence that the avoided cost prices in Oregon or California exceed the Company's actual avoided costs in violation of PURPA.

Q. What justification does Public Counsel provide for the exclusion of the Company's contracts with QFs in Oregon and California?

A. In addition to the arguments addressed above regarding the Company's lack of power flow studies, Public Counsel claims that Oregon and California QF contracts are priced higher than other long term purchase power costs for 2014.[42]

Q. How do you respond to this argument?

A. It is improper for ratemaking purposes to compare the avoided cost price in QF contracts that are several years old with the cost of other purchases in the current NPC study. Such a comparison does not account for the information available at the time the various contracts were entered. Nevertheless, the difference in price cited by Public Counsel was less than seven percent. In addition, all of the long-term contracts included in the comparison were executed more than 10 years ago, including two low-cost contracts entered in 1961 and 1989 that were based on cost-

[42] Exhibit No.___(SC-1CT) at page 17.

of-service rates. It is unreasonable to compare recent avoided cost prices with that of a contract entered more than 50 years ago.

Q. Public Counsel also claims that the Company perceives the Oregon and California QF contracts as local or state-specific matters.[43] Is this correct?

A. No. For every state served by the Company other than Washington, the Company allocates the cost of QF purchases located in all states (including Washington's QF contracts) to all jurisdictions. Washington is the only state served by PacifiCorp that does not reflect their allocated share of other states' QF contracts in NPC.

Q. Boise argues that excluding the Oregon and California QF contracts from west control area NPC is equivalent to replacing these resources with market purchases in GRID.[44] Do agree this is a reasonable approach?

A. No. Boise's argument is based on the incorrect premise that current market prices are an appropriate proxy for avoided cost. Schedule 37 requires the Company to pay QFs in Washington a payment for both energy and capacity, with energy payments reflecting the Company's incremental cost of market transactions and thermal output, and capacity payments reflecting the fixed costs associated with a simple cycle combustion turbine for three months per year. The inclusion of capacity payments in avoided costs indicates that market prices alone are not equivalent to avoided cost prices.

Q. What does the Company recommend regarding the treatment of California and Oregon QF contracts in west control area NPC?

A. The Company recommends that the Commission allow the Company to include

[43] *Id.* at 16.
[44] Exhibit No.___(MCD-1CT) at page 7.

California and Oregon QF contracts in the determination of west control area NPC in the same manner as all other west control area generation resources, with a portion of the costs allocated to Washington customers.

East Control Area Sale

Q. How do parties respond to the Company's proposal to remove from the NPC calculation the assumed sales from PacifiCorp's west control area to its east control area?

A. Boise and Staff each recommend that the Commission reject the Company's proposal and recommend that west control area NPC continue to include an assumed east control area sale.[45]

Q. What is the basis for Boise's opposition to the Company's proposal?

A. Boise provides no factual argument, but instead rejects the proposal to remove the east control area sale because the parties to the collaborative process did not agree to the change.[46] For the same reasons discussed above, this argument is unpersuasive.

Q. What basis does Staff provide for the inclusion of the east control area sale?

A. Staff's argues that the imputed east control area sale remains an integral and crucial part of the WCA and should therefore not be modified.[47]

Q. When the Commission adopted the WCA, what did it say with respect to the east control area sale?

A. The Commission noted that the Company accepted the east control area sale subject to further scrutiny in the future and approved the establishment of a monitoring

[45] Exhibit No.___(DCG-1CT) at pages 13-16; Exhibit No.___(MCD-1CT) at page 8.
[46] Exhibit No.___(MCD-1CT) at page 8.
[47] Exhibit No.___(DCG-1CT) at page 16.

CONFIDENTIAL PER WAC 480-07-160
Exhibit No.___(GND-1CT)
Docket UE-14____
Witness: Gregory N. Duvall

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFIC POWER & LIGHT COMPANY, a division of PacifiCorp Respondent.	Docket UE-14____

PACIFIC POWER & LIGHT COMPANY

REDACTED DIRECT TESTIMONY OF GREGORY N. DUVALL

May 2014

differences in west control area loads and resources by reducing actual short-term balancing purchase or sales transactions.

PROPOSED TREATMENT OF QF RESOURCES IN THE WEST CONTROL AREA

Q. Please explain the Company's proposed treatment of PPAs with west control area QFs.

A. In this case, the Company renews its proposal to include Washington's share of the costs and benefits associated with all PACW (Oregon, California, and Washington) QF PPAs in the calculation of west control area NPC.

Q. Did the Company originally propose this treatment in the 2013 Rate Case?

A. Yes. The Commission rejected this proposal in Order 05 the 2013 Rate Case, and the Company sought judicial review of this issue.

Q. Why is the Company again asking to include the cost of PPAs with QFs in Oregon and California in this case?

A. The Company respectfully asks the Commission to reconsider its approach to including PPAs with west control area QFs in Washington rates for the following reasons:

- Including all PPAs with QFs in the west control area in the NPC calculation is consistent with the treatment of other generation resources under the WCA and is a more accurate representation of the Company's operations in the west control area because these resources are all located in the west control area, physically deliver power to meet Washington load in the same manner as any other west control area resource, and provide direct benefits to Washington customers.
- There are now a material number of QFs serving Washington customers, but the costs of the PPAs with these QFs are not reflected in Washington rates. In the pro forma period, Oregon and California QFs are projected to supply 806,799 megawatt-hours (MWh) of generation in the west control area. Collectively, west control area QFs provide a significant source of power supply to Washington

customers, but Washington customers only pay for PPAs with QFs located in Washington.

- Including west control area QF PPAs in Washington rates is consistent with the Public Utility Regulatory Policy Act of 1978 (PURPA). The QF PPAs included in this case were executed at avoided cost prices calculated under PURPA, and no party has ever alleged that the prices exceed the Company's actual avoided costs at the time the PPAs were executed. PURPA explicitly requires FERC to "ensure that an electric utility that purchases electric energy or capacity from a [QF] . . . recovers all prudently incurred costs associated with the purchase."[2]

- All of the Oregon and California PPAs are with QFs that are eligible resources under Washington's Energy Independence Act (EIA). Allowing the Company to recover the costs of these Oregon and California QF PPAs in rates implements the EIA's policy of encouraging renewable resource development on a regional basis and diversifying the portfolio of renewable resources serving Washington customers.

Q. In the 2013 Rate Case, the Commission reasoned that the Company's proposal was the equivalent of adopting the Revised Protocol method just for QF resources.[3] Do you agree?

A. No. The Company's proposal to include the costs of PPAs with QFs in Oregon and California in the calculation of west control area NPC is consistent with the WCA and strictly tracks the Commission's underlying rationale for the WCA. As reiterated in the 2013 Rate Case Order, the WCA is based "on the generation resources that are actually used to keep the west control area in balance with its neighboring control areas."[4] Oregon and California QFs are used to keep the west control area in balance just like all other west control area generation resources. The only distinguishing

[2] 16 U.S.C. § 824a-3(m)(7)(A); *see also Freehold Cogeneration Assocs., L.P. v. Bd. of Regulatory Comm'rs of the State of N.J.*, 44 F.3d 1178, 1194 (3d Cir. 1995) ("[A]ny action or order by the [state commission] to reconsider its approval or to deny the passage of those rates to [the utility's] consumers under purported state authority was preempted by federal law.").
[3] *Wash. Utils. & Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light Co.*, Docket UE-130043, Order 05, ¶ 110 (Dec. 4, 2013).
[4] Order 05 ¶ 110 (quoting *Wash. Utils. & Transp. Comm'n v. Pacific Power & Light Co.*, Docket UE-061546, Order 08, ¶ 53 (June 21, 2007).

factor between QF resources and all other west control area resources is the fact that PURPA requires the Company to purchase power from QFs at prices established by regulators in west control area states. This mandate makes recovery of the costs of these resources more appropriate under the WCA, not less.

In addition, the 2010 Protocol, which is the current inter-jurisdictional allocation methodology used in the PacifiCorp's other five state jurisdictions, allocates the costs of QF PPAs across PacifiCorp's system. In this case, the Company is not proposing to system-allocate PPAs with QFs in all six states served by the Company.

Q. Are Washington customers harmed because west control area NPC is higher when all PPAs with west control area QFs are included?

A. No. Washington customers are not harmed by paying rates that more accurately represent the cost to serve them. These resources are used in providing service to Washington customers, and including the costs of these resources in rates is fair, not harmful.

Furthermore, while including all west control area QF PPAs increases Washington-allocated NPC by approximately $10.0 million, this only shows that the prices paid for Oregon and California QF resources are higher than the variable cost of market purchases and other resources used to balance the GRID study. QF prices, on the other hand, are established in advance, consistent with PURPA, and are fixed for a number of years over the term of the PPA. Long-term contract prices will inevitably be different from short-term market prices as time progresses. QF prices may also include a capacity component in addition to payment for energy. In

Washington, for example, Schedule 37 rates compensate QFs for both energy and capacity, with energy payments based on the incremental cost of market transactions and thermal output, and capacity payments reflecting the fixed costs of a simple cycle combustion turbine for three months per year. If avoided cost prices are greater than market prices years after the PPA was signed, it does not mean that the avoided cost prices in the QF PPA are excessive or otherwise violate PURPA's strict requirements.

PURPA requires that the prices paid to QFs be equal to a utility's avoided cost of energy and capacity. Each state has an approved method for calculating these avoided costs, and the resulting prices are heavily scrutinized and ultimately approved by the respective regulatory commissions. The avoided cost calculation is intended to ensure that customers are indifferent to QF generation, *i.e.,* that the price paid to the QF is the same as the price the utility would otherwise incur if it was generating the electricity itself. Comparing QF PPA prices for a single test year to the variable cost of market purchases or the Company's existing resources is insufficient to determine whether QF prices are reasonable and prudent from a ratemaking standpoint.

Q. In response to Order 05 in the 2013 Rate Case, did the Company analyze other approaches to addressing Oregon and California QF PPAs in Washington?

A. Yes. In an effort to respond to the Commission's concerns in Order 05 about including the energy and capacity costs of all west control area QF PPAs in the determination of west control area NPC, the Company examined two alternative approaches to addressing the Oregon and California QF PPAs:

1) A "load decrement" approach, which excludes the costs and energy of Oregon and California QF PPAs from the NPC calculation, and excludes an equivalent

amount of QF output from WCA loads used to calculate NPC and inter-jurisdictional allocation factors; and

2) A "Washington re-pricing" approach, which includes Oregon and California QF PPAs in the NPC calculation but re-prices them using the Washington avoided cost rates in effect at the time of PPA execution.

Table 2 below compares the revenue requirement impact of these two alternative approaches with the Company's proposal to include all west control area QF PPAs as west control area resources. This table, and supporting detail, is provided in Exhibit No.___(NCS-7) accompanying Ms. Siores testimony.

Table 2

	Revenue Requirement	Variance from Filed
As Filed	$27.2 million	
Washington Re-Pricing	$24.9 million	($2.3 million)
Load Decrement	$23.1 million	($4.1 million)
Situs Assigned (exclude OR and CA QF PPAs)	$17.2 million	($10.0 million)

Q. Please explain the load decrement approach.

A. Under this approach, Oregon and California QF PPAs are deemed to serve customers in those states, consistent with the situs treatment ordered by the Commission in the 2013 Rate Case. Because Oregon and California QF PPAs are not recognized as WCA resources, the costs and related energy are removed from the calculation of west control area NPC. Next, because Oregon and California QF PPAs are deemed to serve customers in those states, the retail load in those states served by these resources is also removed from the calculation of west control area NPC. Finally, the retail load in Oregon and California served by QF resources is subtracted (*i.e.* decremented) from the energy and peak loads used to determine each state's allocation factors under the WCA.

Q. **What is the impact to Washington of removing Oregon and California QF PPAs and load?**

A. Removing Oregon and California QF PPAs and load reduces west control area NPC and reduces the total load served by west control area resources. The allocation of remaining west control area costs is adjusted to account for the decremented load—*i.e.* the share of the total costs allocated to Oregon and California is decreased reflecting the reduced requirement to serve customers in those states. Washington's allocated share of remaining WCA costs is increased as a result of the QF-PPA-related decrements to Oregon and California load. The net impact is a reduction to the Company's current filing of approximately $4.1 million.

Q. **Why is an adjustment to the inter-jurisdictional allocation factors required under the load decrement approach?**

A. Adjusting the inter-jurisdictional allocation factors under the load decrement approach ensures that the full impact of treating QF PPAs as situs resources is reflected in Washington revenue requirement. If Oregon and California customers are being served by specific resources, they should not also be allocated the cost of the remaining west control area resources. Decrementing Oregon and California load for allocation purposes appropriately reduces the share of west control area costs allocated to those states.

Q. **Please explain the alternative approach of re-pricing Oregon and California QF PPAs using Washington avoided costs.**

A. Under this alternative, the Oregon and California QF PPAs are included in west control area NPC but are re-priced using Washington avoided cost rates that were calculated at the time the PPA was signed. This alternative removes the impact of differences in individual state commission approaches to determining avoided cost prices. Some of the Oregon and California QF PPAs have contract terms that extend beyond the last year for which the Company had calculated avoided cost prices in Washington. For example, an Oregon QF PPA signed in June 2009 would be priced using the Washington Schedule 37 prices approved by the Commission in February 2009, which were only calculated through 2013. In examples such as this, the last annual price was escalated with inflation through the pro forma period. Several Oregon and California QF PPAs in the pro forma period were signed in the early 1980s, and one was signed in the early 1990s. At that time, the Company also had two-long term QF PPAs in Washington, one with the City of Walla Walla (signed in 1984) and one with Yakima-Tieton Irrigation District (signed in 1985). Prices paid under the Walla Walla PPAs were applied to the early-1980s contracts in Oregon and California, and prices paid under the Yakima Tieton PPA were applied to the PPA signed in 1993.

Q. Currently, the Company's Schedule 37 only allows fixed-price contracts for a term of up to five years. Has that always been the case?

A. No. Schedule 37 was first implemented in 2004, and it included a five-year limit on fixed-price contracts. However, the two long-term Washington QF PPA contracts signed in the 1980s mentioned above were for terms of 25 and 20 years, respectively. Washington's current administrative rules allow a utility to sign contracts for electricity purchases for any term up to twenty years.[5]

[5] WAC 480-107-075(3).

Q. What is the impact to Washington NPC of re-pricing all of the Oregon and California QF PPAs?

A. As shown in Table 2, the impact of re-pricing all of the Oregon and California QF PPAs using contemporaneous Washington avoided cost rates is a reduction to the Company's current filing of approximately $2.3 million.

Q. Why is the Company discussing these alternative methods in this case?

A. The Company's proposal for treatment of west control area QF PPAs in this case is the same as in the Company's 2013 Rate Case—full recognition of the costs of the Company's PPAs with Oregon and California QFs in Washington rates. The Company renews this proposal because it best captures the prudent and reasonable costs to serve Washington customers. But in response to the Commission's past criticism of its proposal, the Company provides the alternative methods as a middle ground between full recovery or full disallowance of the costs of all west control area QFs in Washington NPC.

CHANGES IN SALES AND LOADS

Q. Please summarize the changes in Washington sales in this case compared to the Company's 2013 Rate Case.

A. As shown in Table 3 below, the Company's Washington sales in the historical test period (the 12 months ended December 31, 2013) were 9,549 MWh, or 0.2 percent higher than the sales included in the 2013 Rate Case on a weather-normalized basis.[6] The increase in sales is largely driven by increased sales to the commercial class and

[6] In this case, the Company calculated temperature normalization for the residential, commercial, and irrigation customers consistently with the methodology approved by the Commission in the Company's 2005 general rate case, Docket UE-050684, 2006 general rate case, Docket UE-090205, and the Company's 2013 Rate Case, Docket UE-130043.

Exhibit No. GND-4T
Docket UE-140762 *et al.*
Witness: Gregory N. Duvall

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFIC POWER & LIGHT COMPANY,** **Respondent.**	**DOCKETS UE-140762 and UE-140617 (*consolidated*)**
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Colstrip Outage.**	**DOCKET UE-131384 *(consolidated)***
In the Matter of the Petition of **PACIFIC POWER & LIGHT COMPANY,** **For an Order Approving Deferral of Costs Related to Declining Hydro Generation.**	**DOCKET UE-140094 *(consolidated)***

PACIFIC POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF GREGORY N. DUVALL

November 2014

its members, "including the Packaging Corporation of America, f/k/a Boise White Paper, L.L.C. (PCA), PacifiCorp's largest customer in Washington[,]"[14] and further stated that "ICNU indirectly participated in PacifiCorp's most recent general rate case (UE-130043) as PCA[.]"[15]

Q. Given that this update is occurring in your rebuttal testimony, does the Company object to allowing the parties an opportunity to provide responsive testimony on this issue?

A. No. The Company does not object to parties addressing the Company's NPC update in supplemental pre-filed testimony or in testimony at the hearing, provided the Company has a chance to respond to this testimony.

COMPANY RESPONSES TO PROPOSED NPC ADJUSTMENTS

Exclusion of California and Oregon QF PPAs

Q. Does any party support the Company's proposal to include the costs associated with Oregon and California QF PPAs in west control area NPC?

A. No. Staff, Boise, and Public Counsel each reject including California and Oregon and QF PPAs in west control area NPC.[16] Similar to arguments made in the Company's 2013 general rate case, Staff and Boise assert that allocating west control area QF PPAs to Washington inappropriately requires Washington customers to pay for QF-related policy choices made by California and Oregon. Public Counsel does not address the appropriate allocation of California and Oregon QF PPAs, but indicates

[14] *See Wash. Utils. & Transp. Comm'n v. PacifiCorp,* Docket No. UE-140617, Petition to Intervene and Opposition of the Industrial Customers of Northwest Utilities, ¶ 3 (Apr. 25, 2014).
[15] *Id.*, ¶ 4.
[16] *See* Testimony of David C. Gomez, Exhibit No. DCG-1CT at 9-10; Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 23.

that Public Counsel supports the Commission's findings in Docket UE-130043 (2013 Rate Case) and removes the cost of these QFs from west control area NPC.

Q. Is the Company's proposal in this case exactly the same as in the Company's 2013 Rate Case?

A. No. While the Company's main proposal in this case is similar to the 2013 Rate Case in that the costs associated with California and Oregon QF PPAs are included in west control area NPC, the Company also provided two alternative approaches that would reasonably reflect the impact of California and Oregon QF PPAs on NPC. First, the Company proposed re-pricing the out-of-state QFs at Washington avoided cost prices, so that the costs associated with the QFs reflected Washington state policy choices. This proposal would decrease Washington revenue requirement by $2.2 million. Second, the Company proposed a load decrement approach to QF pricing that would remove the costs of the out-of-state QF PPAs and also offset each west control area states' load with the QFs in that state for purposes of allocating costs and benefits under the WCA. This proposal would decrease Washington revenue requirement by $3.9 million. The rebuttal testimony of Ms. Natasha C. Siores provides the detailed revenue requirement impact of each proposal. I reproduced her summary table here for ease of reference.[17]

TABLE 1

Revenue Requirement Summary

	Revenue Requirement	Change from Filed	
Rebuttal Position	31,938,957		**Ref NCS-11, Page 1.**
Re-Pricing at WA QFs Avoided Costs	29,763,224	(2,175,733)	**Ref NCS-12, Page 2**
Load Decrement	28,009,625	(3,929,332)	**Ref NCS-12, Page 3**
Situs-Assigned - Excl. OR/CA QFs	22,181,879	(9,757,079)	**Ref NCS-12, Page 4**

[17] Rebuttal Testimony of Natasha Siores, Exhibit No. NCS-12.

Q. Did the parties address the Company's alternative proposals?

A. Yes. Both Staff and Boise dismissed the Company's alternative proposals as inconsistent with the Commission's decision in the 2013 Rate Case.

Q. What is the parties' primary argument against Pacific Power's proposals?

A. Based on the Commission's order in the 2013 Rate Case, Staff and Boise argue that excluding the California and Oregon QF PPAs from the west control area NPC is equivalent to replacing these resources with market purchases in GRID.[18] Staff and Boise claim that re-pricing the QF PPAs at market prices protects Washington customers from policy decisions made by other states and is consistent with the cost causation principles underlying the WCA.

Q. Is re-pricing the out-of-state QF PPAs at current market prices consistent with PURPA?

A. No. It is my understanding that re-pricing the out-of-state QF PPAs at current spot market prices is inconsistent with PURPA's requirement, as interpreted by the Commission in the Company's Schedule 37, that utilities purchase all energy and capacity made available by QFs at the utility's avoided cost.

Q. Why is re-pricing the out-of-state QF PPAs at current market rates inconsistent with PURPA's avoided cost requirements?

A. There are two primary reasons. First, simply relying on market prices does not reflect Pacific Power's actual avoided costs as determined by the Commission because it fails to account for the impact of a QF on the Company's existing resources or the

[18] *See, e.g.*, Testimony of David C. Gomez, Exhibit No. DCG-1CT at 11; Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 25-26.

QF's ability to defer future capacity additions. PURPA requires the Company to purchase energy and capacity made available by QFs.

Second, the *current* market price does not accurately reflect Pacific Power's avoided cost of energy included in long-term QF PPAs that were executed years ago with avoided cost prices determined at the time of execution. PURPA allows QFs to enter into long-term PPAs with utilities and, at the option of the QF, the avoided cost prices in those PPAs can be determined at the time the PPA is executed, not at the time that the energy is delivered to the utility.

The Commission's decision to price out-of-state QF PPAs at the current market price ignores the Company's obligation under PURPA to pay a fixed avoided cost price over the life of the QF PPA. Thus, even if market prices accurately reflected Pacific Power's avoided cost of energy, the relevant market prices were those that were forecast at the time the QF PPAs were executed, not current spot market prices.

Q. Has the Commission recognized that avoided cost prices must account for both energy and capacity?

A. Yes. Pacific Power's current Schedule 37 requires the Company to pay QFs in Washington for both energy and capacity, with energy payments reflecting the Company's incremental cost of market transactions and thermal output, and capacity payments reflecting the fixed costs associated with a simple cycle combustion turbine for three months per year. The inclusion of capacity payments in Washington's avoided cost calculation demonstrates that, in the current view of the Commission, market prices alone are not equivalent to avoided cost prices.

Q. Has Staff recognized that wind resources provide capacity value to Washington customers?

A. Yes. Staff's cost of service testimony expressly recognizes that wind resources provide capacity to meet the Company's peak load.[19] As described in the cost of service testimony of Ms. Joelle R. Steward, the Company's west control area wind resources, including the out-of-state QFs, contribute 25.4 percent of their nameplate capacity to meet total system peak load.

Q. Why is it necessary for the avoided cost prices to account for both energy and capacity?

A. It is my understanding that PURPA mandates the use of avoided cost prices to ensure customer indifference to the QF transaction. In other words, customers should be no better or worse off because Pacific Power is purchasing its energy and capacity from a QF rather than from another source. However, if Washington customers are paying for only the energy from out-of-state QFs, Washington customers are benefiting from the capacity value provided by the QFs without paying for it. Therefore, re-pricing the out-of-state QF PPAs at market prices does not result in customer indifference.

Q. Has the Commission previously recognized the importance of ensuring customer indifference?

A. Yes. The Commission has observed that "[b]y its own terms, PURPA was meant to protect the ratepayers. Avoided cost prices should be established to be no greater than that which the ratepayers would be expected to pay without PURPA."[20]

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[19] Testimony of Jeremy B. Twitchell, Exhibit No. JBT-1T at 15-16.
[20] *Spokane Energy, Inc. v. Wash. Water Power Co.*, Cause No. U-86-114, 1987 WL 1498338 (Apr. 22, 1987).

Q. How do current market prices compare with the market prices at the time the QFs were executed?

A. The majority of the out-of-state QFs were executed within the last six years. During that time, market prices have decreased by more than half. Thus, even if the Commission's re-pricing method was reasonable for purposes of determining the avoided cost of energy, the contracts must be re-priced at the higher market prices that were anticipated at the time each PPA was executed. The Company's re-pricing proposal effectively captures the relevant forward prices and demonstrates the declining market prices.

Q. Staff claims that the Company provided only vague assertions regarding the benefits provided by the out-of-state QFs to Washington customers.[21] Boise claims that the Company did not identify any direct benefit provided by these QFs that would support full cost recovery.[22] What benefits are provided by the out-of-state QFs?

A. In addition to providing the capacity benefits discussed above, the out-of-state QFs provide significant benefits because they are renewable, emission-free generators. Washington state policymakers have been clear that renewable generation provides significant environmental, cultural, economic, and health benefits to Washington residents. Thus, the state has taken extensive measures to mandate and promote the development of exactly the types of resources that Staff and Boise claim provide no benefit to Washington.

[21] Testimony of David C. Gomez, Exhibit No. DCG-1CT at 9.
[22] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 26.

Emission-free resources may act as a hedge against future carbon regulation, the exact nature of which is currently unknown. In fact, the Commission has acknowledged that future carbon regulation may have a significant impact on the Company's operations.[23] The out-of-state QFs, like all of the Company's renewable resources, will help to mitigate that impact.

Q. What other benefits are provided by the out-of-state QFs?

A. The QFs provide diversity to the Company's resource portfolio, which can act to reduce risk. Indeed, *in this case* Mr. Mullins testified on behalf of Boise about the many benefits provided by wind resources, including the out-of-state QFs:

> Portfolio diversification is one of the fundamental principles relied on by utilities in order to develop a least-cost, least-risk portfolio . . . . For purposes of utility planning, this means that a utility will benefit from procuring power supplies that are dependent on many different fuel and resource types.[24]

Thus, Mr. Mullins concluded that the Company's "overall system is benefiting as a result of the diverse nature of all the resources in its portfolio."[25]

Q. Do the QFs allow the Company to avoid other costs?

A. Yes. Without the energy and capacity provided by the QFs, Pacific Power may have had to procure additional resources. These additional resources may or may not have been renewable, yet under the WCA these resources would have been included in Washington rates.

Q. Are there any other benefits provided by QFs?

A. Yes. In a docket before the Public Utility Commission of Oregon (OPUC), Boise's

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[23] *See, e.g.*, *PacifiCorp's 2013 Electric Integrated Resource Plan*, Docket No. UE-120416, Commission Acknowledgement Letter (Nov. 25, 2013).
[24] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 57.
[25] *Id.* at 58.

energy trade association ICNU submitted testimony from its expert Mr. Donald W. Schoenbeck. ICNU's testimony identified 11 different benefits provided by QFs, including the following:

> The second benefit is reliability. A system of 50 smaller generators of 200 MW each is significantly more reliable than a similar size system of 20 larger generators of 500 MW each. The smaller unit system is 100 times less likely to lose 1,000 MW of capacity simultaneously.
>
> * * *
>
> The fourth benefit is system diversity. Because they distribute electrical generation among smaller, more efficient generating facilities, policies that promote cogeneration increase the reliability of an energy portfolio in the same way a diversified investment strategy protects investors.
>
> * * *
>
> The fifth benefit is transmission reliability. Cogeneration provides a major source of distributed generation for the electric grid which is a significant operating benefit. By providing multiple power sources throughout the state, the demand on the state's electrical grid and the risks of losing power when centralized generating facilities fail is reduced.
>
> * * *
>
> The eighth benefit is reduced transmission losses. Cogeneration conserves electricity by producing power near the places it is consumed. This reduces transmission losses and saves an additional amount of fuel from being burned.[26]

Q. Boise also claims that whether or not the out-of-state QF prices are excessive is irrelevant to cost allocation under the WCA.[27] How do you respond?

A. PURPA makes the QF prices extremely relevant. PURPA requires the Company to contract with the out-of-state QFs at prices equal to Pacific Power's avoided cost. The fact that not a single party in this case has argued that the QF PPA prices exceed

[26] *Investigation Relating to Electric Utility Purchases from Qualifying Facilities*, OPUC Docket No. UM 1129, Direct Testimony of Donald W. Schoenbeck on Behalf of the Industrial Customers of Northwest Utilities at 6-7 (Aug. 3, 2004).

[27] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 26.

Pacific Power's avoided cost prices is significant because, without such a finding, it is unreasonable to exclude the QF PPAs from rates.

Q. Staff and Boise also argue that the out-of-state QF PPA prices are driven by policies and decisions made by other states to encourage QF development that should not impact Washington rates.[28] Boise further claims that states have significant leeway in implementing PURPA to "set avoided cost rates at higher or lower levels to reflect state renewable energy policies."[29] How do you respond to these claims?

A. I disagree with Staff and Boise for several reasons. First, I disagree with the implication that California and Oregon have inflated the avoided cost prices in the QF PPAs as a reflection of those states' renewable energy policies. It is my understanding that states cannot set an avoided cost price that includes a "bonus" or "adder" intended to encourage renewable development. FERC has stated:

> [T]he State can pursue its policy choices concerning particular generation technologies consistent with the requirements of PURPA and our regulations, **so long as such action does not result in rates above avoided cost.**[30]

Moreover, no party to this case demonstrated or even alleged that the avoided cost prices included in the out-of-state QF PPAs are greater than the Company's actual avoided costs as of the time the PPAs were executed. Thus, there is no basis to conclude that California and Oregon are manipulating the avoided cost prices to promote state-specific energy or environmental policies.

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[28] Testimony of David C. Gomez, Exhibit No. DCG-1CT at 9-10; Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 24.
[29] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 27.
[30] *Re So. Calif. Edison Co.*, 70 F.E.R.C. ¶ 61,215 at 61,676 (1995) (emphasis added).

Second, it is my understanding that PURPA is specifically intended to encourage QF development. Therefore, Staff's and Boise's argument has merit only if one assumes that Washington has decided to not encourage QF development, a decision that would be contrary to the fundamental purpose of PURPA and contrary to the Commission's prior statements.

Third, as I discussed previously in my testimony, the states' energy policies are strikingly similar and Washington has taken a decidedly regional approach to encouraging renewable energy development. Both Oregon and Washington, for example, have used PURPA development to promote distributed generation. Therefore, the policy differences perceived by Staff and Boise are not as extensive as they claim.

Fourth, if the Commission remains concerned that the avoided cost prices of the California and Oregon in the QF PPAs reflect those states' policy decisions, then the Commission should approve the Company's alternative recommendation to re-price the QF PPAs at avoided cost prices determined according to Washington state policy. As described in more detail below, this re-pricing proposal effectively removes any perceived differences in PURPA implementation and results in Washington rates that indisputably reflect Washington state policy decisions.

Q. Staff and Boise claim that the Company's proposal is based on the "physical flow of power" and not cost causation.[31] How do you respond?

A. I disagree with this characterization. In my testimony, I stress the fact that the out-of-state QFs provide energy and capacity to serve Washington customers because that

[31] Testimony of David C. Gomez, Exhibit No. DCG-1CT at 10; Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 25.

fact—which is undisputed—demonstrates that Washington customers are benefiting from the QFs. As I discuss above, if Washington customers are receiving energy and capacity from these QFs, along with all of the other benefits discussed, then it is reasonable for Washington customers to pay the full costs of the QF PPAs. Otherwise, Washington customers are receiving the benefits without paying the associated costs. Thus, the Company's proposal is consistent with principles of cost-causation.

Q. Staff also discounts the fact that the Commission has allowed Avista Corporation d/b/a Avista Utilities (Avista) to recover the full costs of out-of-state QF PPAs in Washington rates, claiming that the Commission has not always relied on cost causation when allocating costs across multiple states.[32] Staff claims that the Company's out-of-state QF costs are higher than Avista's and therefore must be situs assigned. Do you agree?

A. No. There is no principled basis to allow one Washington utility to recover out-of-state QF costs while denying Pacific Power recovery of the same types of costs. PURPA contains no materiality threshold governing cost recovery. Consistency in regulation requires consistent treatment for all utilities. Simply pointing out that Avista has had fewer out-of-state QFs does not support differing treatment.

[32] Testimony of David C. Gomez, Exhibit No. DCG-1CT at 13.

Q. Staff also claims that the Commission can disregard cost causation based on the degree to which state-specific policies may be driving the avoided cost prices. To support this claim, Staff relies on a 1983 Washington Water Power Company order regarding the allocation of costs for an Idaho QF PPA.[33] Does that order support Staff's position in this case?

A. No. Contrary to Staff's claim that the Commission situs assigned the Idaho QF PPA costs to Idaho, a careful reading of the Commission's order shows that the Commission did not situs assign the QF costs at all. Rather, the Commission determined that the avoided costs in the QF PPA were excessive and disallowed cost recovery of the amounts that exceeded Washington Water Power's avoided costs. In other words, the Commission applied the Company's alternative proposal and re-priced the QF PPA at Washington avoided cost prices.

Q. What is the basis for your conclusion that the Commission re-priced the QF PPA at Washington's avoided cost prices?

A. The issue presented in the case was whether Washington Water Power's proposed rate revision, which would have included the full Washington-allocated costs of the QF PPA, was just and reasonable. The Commission observed that, "[i]n reaching this ultimate determination, the commission must make the underlying determination whether the proposed purchase agreement is based on a proper methodology to calculate the avoided cost as defined by federal and state laws and rules."[34] Thus, the

[33] Testimony of David C. Gomez, Exhibit No. DCG-1CT at 10 (citing *Wash. Utils. & Transp. Comm'n v. Wash. Water Power Co.*, Cause No. U-83-14, Second Suppl. Order, 56 P.U.R.4th 615 (Nov. 9, 1983)).
[34] *Wash. Utils. & Transp. Comm'n v. Wash. Water Power Co.*, Cause No. U-83-14, Second Suppl. Order, 56 P.U.R.4th 615, 1983 WL 909042 at 2 (Nov. 9, 1983).

Commission analyzed whether the avoided cost prices in the QF PPA were consistent with PURPA. The Commission did not simply situs assign the costs to Idaho.

In the Washington Water Power case, Staff concluded that the rates in the QF PPA were higher than Washington Water Power's avoided cost and therefore inappropriate. The Commission agreed, concluding that the "amount to be paid under the purchase agreement is in excess of properly determined avoided costs."[35] Thus, the Commission disallowed cost recovery of the amounts that exceeded the avoided cost price as determined by the Commission. Applying the same standard to this case would require approval of the Company's Washington re-pricing proposal.

Q. Staff testifies that in the Washington Water Power case, the QF PPA "pricing and terms were driven by Idaho state policies at the time."[36] Do you agree with this characterization of the order?

A. No. Nowhere in the order does it suggest that the avoided cost price in the QF PPA was the result of Idaho state policies. In addition, Staff testifies in this case that once the Commission chose to situs assign the costs to Idaho, the Idaho commission accepted that decision. Again, however, the Commission did not situs assign the costs to Idaho, and the order says nothing about how the Idaho commission responded to the Commission's order.

Q. Staff and Boise reject the Company's alternative proposal to re-price the out-of-state QF PPAs as if they were Washington QF PPAs. What is the basis for their rejection of this proposal?

A. The parties argue that this proposal is inconsistent with cost causation and merely

[35] *Id.* at 8.

[36] Testimony of David C. Gomez, Exhibit No. DCG-1CT at 13 n. 24.

discounts the cost impact of state policy decisions made by California and Oregon.[37] Boise also claims that the Washington re-pricing proposal still burdens Washington customers with other states' energy policies because there is no way to know if the out-of-state QFs would have been developed if they had been subject to Washington's PURPA policies.[38]

Q. Does the Company's re-pricing proposal require Washington customers to pay rates that reflect policy decisions made by other states?

A. No. Re-pricing the QF PPAs at Washington avoided cost prices mitigates concerns that the avoided cost prices for the QF PPAs are driven by policy choices made by other states. The use of the avoided cost pricing for QF PPAs is intended to keep customers indifferent to the QF transaction. If the QF PPAs are re-priced at the amount that this Commission has found will result in customer indifference, then customers will be no better or worse off than they would be without the QF PPA. The parties' concerns that the re-pricing proposal still reflects other state's policy decisions has merit only if one assumes that the Commission's avoided cost prices are excessive. The re-pricing proposal, therefore, ensures that Washington rates reflect only the decisions of Washington policy makers.

Q. Doesn't the fact that customers rates will increase by $7.6 million under your re-pricing alternative suggest that the parties' concern has merit?

A. No. The fact that customer rates will increase if they pay the avoided cost prices determined by the Commission suggests that situs assignment of California and

[37] Testimony of David C. Gomez, Exhibit No. DCG-1CT at 15-16; Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 29-30.
[38] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 30.

Oregon QF PPAs has allowed Washington customers to receive benefits for which they have not paid.

Q. Is there any precedent for this type of re-pricing?

A. Yes. As discussed above, the Commission used this approach in the 1983 Washington Water Power case relied on by Staff. It is also my understanding that the North Carolina Utilities Commission (NCUC) took this same approach to a QF PPA that was approved by the Virginia State Corporation Commission (VSCC). The NCUC analyzed the QF PPA and concluded that the pricing exceeded the utility's actual avoided costs.[39] The NCUC therefore denied cost recovery of the amount that the NCUC found to be greater than the utility's avoided costs. It is my understanding that on judicial review, the North Carolina Supreme Court affirmed the NCUC's order, concluding that the disallowance "does not violate PURPA to the extent it only excludes the amount *above* avoided costs."[40]

I also understand that the OPUC approved a stipulation for Idaho Power Company that required Idaho Power to re-price its Idaho QF PPAs to reflect Oregon's non-levelized pricing policy.[41]

Q. Has any party alleged that the Washington avoided cost prices used in the re-pricing alternative proposal do not accurately reflect the Commission's avoided cost prices in effect at the time the out-of-state QFs were executed?

A. No. There is no basis in the record to conclude that the re-pricing does not reflect the

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[39] *Re N. Carolina Power*, E-22, SUB 333, 1993 WL 216264 (Feb. 26, 1993) *aff'd sub nom. N. Carolina Power*, 450 S.E.2d 896.

[40] *State ex rel. Utilities Comm'n v. N. Carolina Power*, 338 N.C. 412, 450 S.E.2d 896, 900 (1994). Importantly, as I discuss above, since this case, FERC has been clear that PURPA prohibits inflating the avoided cost price as the VSCC apparently did to promote state policies.

[41] *Re Idaho Power Co.*, Docket No. UE 257, Order No. 13-166 (May 6, 2013).

costs that would have been incurred if the out-of-state QF PPAs had been executed in Washington.

Q. Staff and Boise both reject the Company's alternative load decrement proposal because they claim it is based on power flows, not cost causation.[42] How do you respond?

A. The load decrement approach is consistent with cost causation. No party disputes that the out-of-state QFs serve Washington customers. Washington customers, however, are not paying their fair share of the costs by paying only current market prices. The load decrement alternative is intended to account for this fact by allocating additional costs to Washington to reflect the benefits Washington customers receive.

Q. Boise claims that the load decrement approach is unreasonable because it would assign more transmission costs to Washington customers even though the presence of QFs in California and Oregon does not reduce those states' use of the Company's transmission network.[43] Does this claim have merit?

A. No. Again, no party disputes that the QFs located in California and Oregon serve Washington customers. As discussed above, Boise's trade group, ICNU, previously testified before the OPUC that distributed generation, like the out-of-state QFs, typically decreases the need for transmission because the electricity is generated closer to load. This is particularly true for the out-of-state QFs because they are typically located closer to California and Oregon load and therefore use less transmission to serve that load. So it is reasonable to credit out-of-state customers for reduced transmission usage due to the QF development in those states.

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[42] Testimony of David C. Gomez, Exhibit No. DCG-1CT at 15; Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 29.
[43] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 29.

Q. Boise claims that it would be unjust, unreasonable, and illegal to include the costs of the out-of-state QF PPAs in rates, in part, because the Commission does not have jurisdiction over the QFs.[44] Is it your understanding that the Commission must have jurisdiction over PPA counterparties to allow cost recovery of the PPAs in rates?

A. No. Most, if not all, of the Company's long-term PPAs are with counterparties that are not public utilities regulated by the Commission. Nevertheless, the costs of these PPAs are regularly recovered in rates. In addition, PURPA specifically exempts QFs from regulation by state utility commissions.

Q. What is the Company's recommended treatment of the costs associated with California and Oregon QF PPAs in west control area NPC?

A. The Company recommends that the Commission allow the Company to include the costs of California and Oregon QF PPAs in west control area NPC in the same manner as all other west control area generation resources, with a portion of the costs allocated to Washington customers. Alternatively, the Company proposes the out-of-state QF PPAs be re-priced using Washington avoided cost prices and then included in the determination of west control area NPC or that the Commission adopt the proposed load decrement adjustment.

Energy Imbalance Market

Q. Please describe Boise's adjustment to NPC related to the EIM.

A. Boise proposes to reduce Washington NPC by more than $5 million based on the Company's participation in the EIM, while also including certain EIM-related costs. Boise proposed this NPC reduction in October 2014 before the EIM even began

[44] Responsive Testimony of Bradley G. Mullins, Exhibit No. BGM-1CT at 25.

Q. Does this conclude your rebuttal testimony?

A. Yes.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NOS. IPC-E-15-01, AVU-E-15-01, PAC-E-15-03

J.R. SIMPLOT COMPANY AND

CLEARWATER PAPER CORPORATION

READING, DI

TESTIMONY

EXHIBIT NO. 205

IDAHO POWER®
An IDACORP Company

DONOVAN E. WALKER
Lead Counsel
dwalker@idahopower.com

April 15, 2015

VIA HAND DELIVERY

Jean D. Jewell, Secretary
Idaho Public Utilities Commission
472 West Washington Street
Boise, Idaho 83702

Re: Energy Sales Agreements Terminations
Case No. IPC-E-14-28, Clark Solar 1, LLC
Case No. IPC-E-14-29, Clark Solar 2, LLC
Case No. IPC-E-14-30, Clark Solar 3, LLC
Case No. IPC-E-14-31, Clark Solar 4, LLC

Dear Ms. Jewell:

On April 6, 2015, Idaho Power Company ("Idaho Power") terminated the Public Utility Regulatory Policies Act of 1978 ("PURPA") Energy Sales Agreements ("ESAs") with each of the above-referenced PURPA qualifying facilities ("QF"). Each of the referenced QF ESAs was approved by the Idaho Public Utilities Commission ("Commission") by Order, as noted in the table below.

Project	Case Number	Order Number	Date of Order
Clark Solar 1, LLC	IPC-E-14-28	Order No. 33208	01/08/15
Clark Solar 2, LLC	IPC-E-14-29	Order No. 33209	01/08/15
Clark Solar 3, LLC	IPC-E-14-30	Order No. 33204	01/08/15
Clark Solar 4, LLC	IPC-E-14-31	Order No. 33205	01/08/15

Erratas to Order Nos. 33208 and 33209 were issued on January 9, 2015.

The ESAs require that a Security Deposit be posted within 30 days of final non-appealable Commission orders approving the ESAs. The required Security Deposits were not paid, and Idaho Power provided Notice of Default and Material Breach on March 2, 2015. Subsequently, Idaho Power and the projects' developer, Intermountain Energy Partners, LLC, entered into an agreement (attached hereto as Attachment 1) setting forth the agreed to provisions by which the projects were to cure the Material Breach of the ESAs. The Security Deposits were not so posted for the above-referenced Clark Solar projects; thus, the associated ESAs were terminated as of April 6, 2015. The Security Deposits for the Mountain Home Solar and Pocatello Solar projects were paid according to this agreement and thus were not terminated.

To keep the Commission apprised of these terminations, Idaho Power has enclosed an original and four (4) courtesy copies of this letter and its attachment for your convenience. Please contact me if you have any comments, questions, or concerns.

Sincerely,

Donovan E. Walker

DEW:csb
Enclosures
cc: Dean J. Miller (w/encl.) – via e-mail
Rick Sterling (w/encl.) – via e-mail
Donald L. Howell, II (w/encl.) – via e-mail

ATTACHMENT 1

IDAHO POWER®
An IDACORP Company

DONOVAN E. WALKER
Lead Counsel
dwalker@idahopower.com

March 17, 2015

joe@mcdevitt-miller.com
Dean J. Miller
McDevitt & Miller LLP
420 W. Bannock Street
P.O. Box 2564-83701
Boise, Idaho 83702

VIA ELECTRONIC MAIL

Re: Security Deposits – Mountain Home Solar 1, Pocatello Solar 1, Clark Solar 1, Clark Solar 2, Clark Solar 3, Clark Solar 4.

Joe:

Idaho Power is in receipt of the memo from Mark van Gulik dated March 17, 2015, regarding the specific arrangements being pursued by Intermountain Energy Partners ("IEP") to cure the material breach of the Energy Sales Agreements ("ESA") for each of the above referenced solar projects "as expeditiously as possible."

Idaho Power will accept your proposed schedule of events outlined in your March 17, 2015, memo which outlines activities starting today to secure the necessary deposits and continuing through the stated deadlines of March 31, 2015, for Mountain Home Solar and Pocatello Solar – and April 3, 2015, for Clark Solar 1 through 4.

Idaho Power will further accept the proposal of a "Non-Appealable" agreement and provision that if the deposits are not paid in accordance with these dates, that the Energy Sales Agreements will immediately terminate, and that IEP will not contest the termination at the Idaho Public Utilities Commission, or elsewhere. Because of the shortness of time before tomorrow's ESA termination deadline, please let this letter serve as both parties' written acknowledgement of this agreement:

Consequently, both Idaho Power Company and Intermountain Energy Partners hereby agree that the final and definitive deadline with which IEP is to cure the material breach of the ESAs for each of the above referenced solar projects under contract with Idaho Power is March 31, 2015, for Mountain Home Solar and Pocatello Solar – and April 3, 2015, for Clark Solar 1 through 4, as set forth in IEPs March 17, 2015, memo, incorporated herein by this reference.

IEP shall cause the appropriate amount of security deposit, as referenced in each project's respective ESA, as well as in Idaho Power's March 2, 2015, Notice of

1221 W Idaho St (83702)
P.O Box 70
Boise, ID 83707

Default: Material Breach – and Idaho Power's March 4, 2015, Notice to Terminate, to be posted on or before 5:00 p.m., mountain time, on Tuesday, March 31, 2015, for the Mountain Home Solar and Pocatello Solar projects – and on or before April 3, 2015, for Clark Solar 1, Clark Solar 2, Clark Solar 3, and Clark Solar 4. If the required security deposit is not paid by these deadlines, then each associated ESA will immediately terminate. IEP will accept said termination and shall not contest said termination in any manner what-so-ever, either in law or equity, before the Idaho Public Utilities Commission or any other forum. Idaho Power understands from IEP's March 17, 2015, memo, and from its conversations with Mr. van Gulik, and Mr. Miller, that the required security will be posted in cash. If an alternative method is utilized (i.e., letter(s) of credit or parent guarantees) then the necessary arrangements and approvals of such alternative methods must be completed on or before the deadline, or the deadline shall be deemed to have NOT been met.

If this is agreeable, please execute this letter below and return a signed copy back to me.

Sincerely,

Donovan E. Walker
Lead Counsel
Idaho Power Company

Agreed to and Accepted by, on behalf of Intermountain Energy Partners:

______________________(Signature)

MARK VAN GULIK______________________(Printed Name)

MANAGER/PRESIDENT______________________(Title)

DEW:csb
cc:

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 23rd day of April, 2015, a true and correct copy of the within and foregoing DIRECT TESTIMONY OF DR. DON READING ON BEHALF OF CLEARWATER PAPER CORPORATION and the J.R. SIMPLOT COMPANY was served as shown to:

Jean D. Jewell, Secretary Idaho Public Utilities Commission 472 West Washington Boise, Idaho 83702 jean.jewell@puc.idaho.gov	X Hand Delivery __U.S. Mail, postage pre-paid __ Facsimile __ Electronic Mail
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Signed Nina M. Curtis
Nina M. Curtis